# DOWNEAST LNG PROJECT

## *Final Environmental Impact Statement*

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| Downeast LNG, Inc. | Docket No. CP07-52-000 |
| Downeast Pipeline, LLC. | Docket Nos. CP07-53-000<br>CP07-53-001 |
| | **FERC\EIS: 0231F** |

**Federal Energy Regulatory Commission**
Office of Energy Projects
Washington, DC 20426

**Cooperating Agencies**

**May 2014**

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY PROJECTS

In Reply Refer To:
OEP/DG2E/Gas 1
Downeast LNG, Inc. and
Downeast Pipeline, LLC.
Downeast LNG Project
Docket Nos. CP07-52-000,
CP07-53-000, and CP07-53-001

TO THE PARTY ADDRESSED:

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared a final environmental impact statement (EIS) for the Downeast LNG Project (Project), proposed by Downeast LNG, Inc. and Downeast Pipeline, LLC (collectively Downeast) in the above-referenced dockets. Downeast requests authorization to construct and operate a proposed liquefied natural gas (LNG) import terminal, natural gas sendout pipeline, and associated facilities in Washington County, Maine. The Downeast LNG Project would provide about 500 million cubic feet per day of imported natural gas to the New England region.

The final EIS assesses the potential environmental effects of the construction and operation of the Project in accordance with the requirements of the National Environmental Policy Act (NEPA). The FERC staff concludes that approval of the proposed Project, with the mitigation measures recommended in the EIS, would ensure that most impacts in the Project area would be avoided or reduced to less than significant levels. Construction and operation of the Project would primarily result in temporary and short-term environmental impacts; however, some long-term and permanent environmental impacts would occur.

The U.S. Coast Guard; U.S. Army Corps of Engineers; National Oceanic and Atmospheric Administration, National Marine Fisheries Service; U.S. Environmental Protection Agency; U.S. Department of Transportation; and the Maine Department of Environmental Protection participated as cooperating agencies in the preparation of the EIS. Cooperating agencies have jurisdiction by law or special expertise with respect to resources potentially affected by the proposal and participate in the NEPA analysis. Although the cooperating agencies provided input to the conclusions and recommendations presented in the EIS, the agencies will present their own conclusions and recommendations in their respective Records of Decision or other determinations for the Project.

The EIS addresses the potential environmental effects of the construction and operation of the following Project facilities:

- a new marine terminal that would include a 3,862-foot-long pier with a single berth and vessel mooring system, intended to handle LNG vessels ranging from 70,000 to 165,000 cubic meters in capacity, with future expansion capabilities to handle vessels with 220,000 cubic meters of cargo capacity;
- two full-containment LNG storage tanks, each with a nominal usable storage capacity of 160,000 cubic meters;
- LNG vaporization and processing equipment;
- piping, ancillary buildings, safety systems, and other support facilities;
- three vapor fences around the LNG terminal;
- a 29.8-mile-long, 30-inch-diameter underground natural gas pipeline;
- natural gas metering facilities located at the LNG terminal site; and
- various ancillary facilities including pigging[1] facilities and three mainline block valves.

The FERC staff mailed copies of the EIS to federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Native American tribes; potentially affected landowners and other interested individuals and groups; newspapers and libraries in the Project area; and parties to this proceeding. Everyone on our environmental mailing list will receive a CD version of the final EIS. Paper copy versions of the EIS were mailed to those specifically requesting them. In addition, the EIS is available for public viewing on the FERC's website (www.ferc.gov) using the eLibrary link. A limited number of printed copies are available for distribution and public inspection at:

Federal Energy Regulatory Commission
Public Reference Room
888 First Street NE, Room 2A
Washington, DC 20426
(202) 502-8371

**Questions?**

Additional information about the project is available from the Commission's Office of External Affairs, at **(866) 208-FERC,** or on the FERC website (www.ferc.gov) using the eLibrary link. Click on the eLibrary link, click on "General Search," and enter the docket number excluding the last three digits in the Docket Number field (i.e., CP07-52 or CP07-53). Be sure you have selected an appropriate date range. For assistance,

[1] A "pig" is a tool for cleaning and inspecting the inside of a pipeline.

please contact FERC Online Support at FercOnlineSupport@ferc.gov or toll free at (866) 208-3676; for TTY, contact (202) 502-8659. The eLibrary link also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. Go to http://www.ferc.gov/docs-filing/esubscription.asp.

Kimberly D. Bose
Secretary

# EXECUTIVE SUMMARY

## INTRODUCTION

The staff of the Federal Energy Regulatory Commission (Commission or FERC) has prepared this final Environmental Impact Statement (EIS) for the Downeast LNG Project (project) to fulfill the requirements of the National Environmental Policy Act (NEPA) and the Commission's implementing regulations under Title 18 Code of Federal Regulations (CFR) Part 380. The purpose of this document is: to inform the public and the permitting agencies about the potential environmental impacts of the proposed project, including the use of the marine transit route for liquefied natural gas (LNG) vessels; identify and discuss project alternatives; and recommend mitigation measures that would avoid or reduce adverse impacts to the maximum extent practicable. The U.S. Department of Transportation (DOT); U.S. Coast Guard (Coast Guard); U.S. Army Corps of Engineers (COE); National Oceanic and Atmospheric Administration, National Marine Fisheries Service (NOAA Fisheries); U.S. Environmental Protection Agency (EPA); and the Maine Department of Environmental Protection (Maine DEP) have acted as cooperating agencies in the development of this final EIS.

The FERC is the federal agency responsible for authorizing applications to construct and operate onshore LNG import and interstate natural gas transmission facilities. The DOT is serving as a subject matter expert on its federal safety standards in 49 CFR 193, and is assisting FERC staff in evaluating whether the proposed project design would meet the DOT requirements. The Coast Guard is serving as a subject matter expert for, and providing recommendations on, the maritime safety and security aspects of the project. The Coast Guard is responsible for assessing the suitability of the waterway and issuing a Letter of Recommendation (LOR). The LOR is considered by FERC, as the siting authority, to assist with its decision concerning approval of the project.

## PROJECT BACKGROUND

On January 5, 2006, we[1] approved a request by Downeast LNG, Inc. to use the Commission's pre-filing review process in order to identify and address project-related issues prior to the filing of an application with the Commission. On December 22, 2006, Downeast LNG, Inc. and Downeast Pipeline, LLC (hereafter collectively referred to as Downeast) filed an application with the FERC under Section 3(a) and Section 7(c) of the Natural Gas Act to construct, operate, and maintain an LNG import facility, associated sendout pipeline, and various ancillary facilities. On January 16, 2008, Downeast filed an amendment to its Section 7(c) application to modify the proposed pipeline route and avoid crossing the Moosehorn National Wildlife Refuge, owned and managed by the U.S. Fish and Wildlife Service (FWS). We have prepared our analysis based on Downeast's application and subsequent filings that included filings to address DOT's clarifications on its safety standards between the draft and final EIS.

[1] "We," "us," and "our" refer to the environmental staff of the Federal Energy Regulatory Commission's Office of Energy Projects.

## PROPOSED ACTION

In Docket No. CP07-52-000, Downeast proposes to import, store, and vaporize LNG, and sendout natural gas on average about 500 million cubic feet per day (MMcfd) with peak deliveries of 625 MMcfd at a terminal facility on the south side of Mill Cove in the Town of Robbinston, Washington County, Maine. The LNG terminal would be located on an 80-acre parcel, near the confluence of Passamaquoddy Bay and the St. Croix River. Downeast requests Commission authorization to construct and operate the following facilities:

- a new marine terminal that would include a 3,862-foot-long pier with a single berth;
- two full-containment LNG storage tanks, each with a nominal usable storage capacity of 160,000 cubic meters;
- LNG vaporization and processing equipment; and
- various ancillary facilities and buildings.

In Docket Nos. CP07-53-000 and CP07-53-001, Downeast requests Commission authorization to construct and operate natural gas sendout pipeline facilities that consist of:

- a 29.8-mile-long, 30-inch-diameter natural gas pipeline;
- natural gas metering facilities located at the LNG terminal site;
- pig launching and receiving facilities; and
- three mainline block valves.

The proposed sendout pipeline would transport natural gas from the LNG terminal to an interconnect point with Maritimes and Northeast Pipeline L.L.C. (M&NE) near the town of Baileyville, Maine.

In our draft EIS, the sections on each resource area contained a discussion of the potential impact of an LNG spill, ignited or unignited, occurring along the waterway for LNG marine traffic to assist the Coast Guard in fulfilling its NEPA obligations related to the issuance of the LOR. Since issuance of the draft EIS, the Coast Guard has determined that the LOR is not a federal action and that the agency has no NEPA obligations which need to be addressed by the FERC EIS. As a result, we have removed the discussion on environmental resources that may be present in the Coast Guard's Zones of Concern. The discussion regarding the Zones of Concern considered by the Coast Guard in its determination on the type and frequency of LNG marine traffic associated with this proposed project is in the Safety and Reliability section 4.12.7.

## PUBLIC OUTREACH AND COMMENTS

On March 13, 2006, the FERC issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Downeast LNG Project, Request for Comments on Environmental Issues, and Notice of a Joint Public Meetin*g (NOI) that briefly described the project; the EIS process; explained the FERC and Coast Guard's coordinated reviews; and invited public comments on the environmental issues to be addressed in the EIS. Subsequent to this initial NOI, FERC issued the following Supplemental NOIs:

- September 18, 2006, to describe two additional natural gas sendout pipeline routes that had been identified since the initial NOI and to request comments on the new preferred route;
- December 1, 2006, to describe potential M&NE downstream expansion facilities; and
- February 13, 2008, to describe the modification of the proposed natural gas sendout pipeline route to avoid crossing the Moosehorn National Wildlife Refuge, and request comments on the amended pipeline route.

The notices were published in the *Federal Register* and sent to affected landowners; federal, state, and local government agencies; elected officials; environmental and public interest groups; Native American tribes; local libraries and newspapers; and other interested parties on our environmental mailing list.

On March 28, 2006, the FERC and the Coast Guard conducted a joint public scoping meeting in Robbinston, Maine to provide an opportunity for the public to learn more about the proposed project and provide comments and concerns. On March 28, 2006, the FERC also conducted a public site visit of Downeast's LNG terminal site and the proposed pipeline route.

In response to our notices and public meetings, we received numerous comments expressing concerns for safety; alternatives; purpose and need; wildlife habitat; threatened and endangered species; tourism; commercial fishing; United States-Canadian economic relations; and property values in proximity to the project facilities. Additional issues were identified through communications between Canadian governmental officials and the FERC. The Canadian government's concerns include navigational challenges of the proposed transit route; safety and security zones associated with LNG tankers; and the impacts of accidents such as spills from the terminal facilities or LNG vessels. The Canadian government's concerns are addressed in this EIS and the Coast Guard's Waterway Suitability Report (WSR).

On May 15, 2009, the FERC issued a draft EIS for the project that was mailed to all parties on our environmental mailing list. The draft EIS was also submitted to the EPA for issuing its formal public Notice of Availability (NOA) in the *Federal Register*. The public had 45 days after the date of EPA's notice to review and comment on the draft EIS, ending on July 6, 2009. The FERC held one public comment meeting on the draft EIS on June 16, 2009, in Robbinston, Maine. The meeting provided interested parties with an opportunity to present oral comments on the analysis of the environmental impacts of the proposed project as described in the draft EIS. Additionally, written letters were received by FERC in response to the draft EIS. All environmental comments on the draft EIS have been addressed in this final EIS.

On March 28, 2013, the FERC issued a Supplemental draft EIS for the project, which was mailed to the agencies, individuals, and organizations on our environmental mailing list, and was filed with the EPA for issuance of a formal NOA in the *Federal Register*. The scope of the Supplemental draft EIS was limited to a revised reliability and safety analysis of the LNG terminal and carrier transit, to address DOT clarifications on its safety standards in 49 CFR 193. The public had 45 days after the EPA's notice to review and comment on the Supplemental draft EIS, ending on May 20, 2013. Written letters were received in response to the Supplemental draft EIS, and these comments have been addressed in this final EIS.

## ENVIRONMENTAL IMPACTS AND MITIGATIONS

We evaluated the impacts of the project, as reduced by Downeast's proposed mitigation measures, on geology, soils, water resources, vegetation, wildlife, fisheries, special status species, land use, visual resources, socioeconomics, cultural resources, air quality, noise, and safety. We also considered the cumulative impacts of this project with other past, present, and reasonably foreseeable actions in the project area and potential alternatives to the proposed action. Where necessary, we have recommended additional mitigation measures to minimize or avoid these impacts. Section 5.2 of this EIS contains a compilation of recommendations.

The major issues identified in our analysis are potential impacts on waterbodies and wetlands; sensitive wildlife habitats and fisheries; listed endangered and threatened species; residences; visual resources; commercial and recreational marine vessel activity; cultural resources; air and noise impacts; and safety.

The proposed sendout pipeline would cross 22 surface waterbodies; Downest would cross the majority of these waterbodies using conventional backhoe-type equipment and dry-ditch techniques. Downeast would use horizontal directional drill (HDD) techniques at selected rivers including those with riffle pool habitats, the St. Croix River, and the Magurrewock Stream Outlet. These proposed crossing methods would minimize or avoid instream impacts on waterbodies.

During terminal operations, water would be routinely withdrawn from Passamaquoddy Bay for LNG vessel engine cooling, ballasting, hoteling, and weekly testing of the fire suppression system. Water withdrawals would impinge and entrain zooplankton and ichthyoplankton; however, based on Downeast's sampling and modeling analyses, we have determined that impacts on overall community populations and associated fish stocks would be insignificant.

The primary impact on wildlife would be clearing of forested habitats, impacts on forested and scrub-shrub freshwater wetlands, and disturbance of vernal pools that provide habitat for sensitive species. Downeast located the proposed pipeline right-of-way immediately adjacent to existing rights-of-way to the greatest extent practical to minimize forest habitat loss and fragmentation. Downeast would minimize impacts on vernal pools by implementing the measures in its *Upland Erosion Control, Revegetation, and Maintenance Plan* (Plan), *Soil Erosion and Sediment Controls Guidelines*, and the Maine DEP's guidance for construction and mitigation for vernal pool disturbance. At the terminal site, Downeast would compensate for the permanent loss of wetlands through a compensation plan in consultation with the COE and state agencies that addresses coastal and freshwater wetlands, areas used by tidal and inland wading waterfowl, and significant vernal pools. In addition, Downeast has finalized a Shorebird Mitigation Plan to compensate for shorebird impacts and would continue consultations with the Maine Division of Inland Fish and Wildlife to develop Deer Wintering Area (DWA) mitigation measures.

Potential impacts on marine mammals may include LNG vessel collisions, acoustic harassment, during the pier construction, physical harassment, and exposure to pollutants and marine debris. To minimize and/or avoid potential impact on marine mammals, Downeast would apply mitigation methods specific to the North Atlantic right whale to all marine mammals. Downeast is developing a Prevention and Mitigation Manual in consultation with NOAA Fisheries for construction and operation that outlines mitigation strategies such as limiting LNG vessel speed, use of forward watching whale spotters, and training and education programs. Downeast has also proposed measures to minimize or avoid acoustic impacts, and would continue its consultations with the FWS and NOAA Fisheries to determine the final approved construction and mitigation measures and incorporate those measures into its comprehensive Prevention and Mitigation Manual.

Informal consultations and review of published information identified 46 federal and/or state special status species that could potentially occur in the project area, and designated critical habitat for 3 of these species. We conclude that the project would have no effect on 34 of these species or the 3 designated critical habitats. We conclude the project would not likely adversely affect the remaining 12 species. Within the project area, we also identified designated essential fish habitat (EFH) for 29 species of finfish, 3 species of shellfish, and 4 species of skate. A Biological Assessment (BA) is included as Appendix C and an EFH Assessment is included as Appendix G of this EIS. We initiated formal consultation with the FWS and NOAA Fisheries on May 19, 2009, and provided a revised BA in June 2012. To ensure compliance with the Endangered Species Act and Magnuson-Stevenson Act, we are recommending that Downeast not begin construction until the FERC staff completes consultation with the FWS and NOAA Fisheries.

In the draft EIS, we identified 19 residences within 50 feet of the permanent right-of-way for the sendout pipeline, and included Downeast's site-specific plans for construction near these residences. Since the draft EIS, Downeast identified potential route variations and workspace alternatives to minimize impacts on several of these residences. After Downeast incorporated these variations into its proposed pipeline route, only two of the residences are still within 50 feet of the proposed construction right-of-way. We have included Downeast's revised site-specific plans for construction near these residences in Appendix P of this EIS. The closest residence is located 125 feet from the proposed LNG terminal boundary.

There are no public lands or other designated federal, state, or local recreation areas located on or within 0.25 mile of the LNG terminal site. Visual impacts associated with the Downeast LNG terminal include the proposed pier, LNG storage tanks, and the vapor fences. To mitigate these impacts, the storage tanks would be painted a neutral color and equipment specifically designed to reduce off-site light spillage would be used. We are also recommending that Downeast file a mitigation plan to reduce the potential visual impact of the proposed outer vapor fence.

Operation of the project could result in regular transit of approximately 60 LNG vessels per year in the Bay of Fundy, Grand Manan Channel, Head Harbour Passage, Western Passage, and Passamaquoddy Bay. A moving security zone imposed around LNG vessels, as recommended by the Coast Guard in their WSR, could impact commercial, recreational, and fishing boats during the arrival and departure of the LNG vessels. Given the limited amount of LNG vessel traffic, implementation of vessel traffic management practices recommended by the Coast Guard, advance notice to United States and Canadian authorities from the LNG vessels transiting the area, and the limited time that nearby marine traffic could be interrupted, we have determined that impacts on commercial and recreational marine activity would not be significant. Downeast has consulted with the Cobscook Bay Fishermen's Association, the Fundy North Fishermen's Association, and other sources to develop a comprehensive compensation plan to address any potential loss of fishing equipment or income as a result of unavoidable impacts by Downeast

LNG vessels. We are recommending that, prior to operation of the Downeast LNG terminal, Downeast file the final Fishermen Communication, Coordination and Compensation Plan.

The Bureau of Indian Affairs and Passamaquoddy Tribe have expressed concern for potential project impacts on sites of religious and cultural importance, including archaeological sites, burials, historic properties, and aboriginal fishing rights. We are recommending that Downeast file documentation of continued consultations with the Passamaquoddy Tribe and other Native Americans and seek resolution of identified project-related impacts on cultural and religious interests. In addition, we are recommending that Downeast not begin construction and/or use of all proposed facilities until it files the remaining survey and evaluation reports, any required treatment plans, comments of the State Historic Preservation Officer and appropriate Indian Tribes, and the Director of the Office of Energy Projects (OEP) notifies Downeast in writing that it may proceed with treatment or construction. These recommended measures would ensure that the FERC's responsibilities under Section 106 of the National Historic Preservation Act are met before Downeast begins construction of the project.

We evaluated the air quality impacts from construction and operation of the Downeast LNG terminal as well as construction and operation of the sendout pipeline. Construction air impacts from the Downeast LNG terminal and the pipeline would be temporary and minor, although residents near the construction areas may see an elevated level of fugitive dust during construction. While there would be no operational emissions from the pipeline, there would be emissions from the Downeast LNG terminal. These emissions were evaluated using various modeling techniques and we determined that the project would not have significant impact on local or regional air quality but could have a significant adverse impact on nearby Class I areas due to deposition of sulfur and nitrogen.

The noise impacts from construction and operation were evaluated for both the Downeast LNG terminal and the pipeline. Construction noise impacts on both residents and wildlife species from the pipeline would be temporary and minor. Construction impacts of the LNG terminal and pier would have the potential for significant impacts on local residents due to pile driving; however, Downeast would reduce the impact levels below significance through the use of vibratory pile drivers. In addition, Downeast would implement the recommendations from NOAA Fisheries to ensure that in-water pile driving would not have significant impact on aquatic species. We are recommending that Downeast conduct post-construction noise surveys for the Downeast LNG terminal and for the pipeline meter station at the LNG terminal to ensure noise impacts would not be significant. Therefore, we determined that with Downest's mitigation and our recommendations, the noise impacts from construction and operation of the LNG terminal and pipeline would not be significant.

We evaluated the safety of the proposed LNG import terminal facility, the related LNG vessel transit through the Passamaquoddy Bay Waterway, and the sendout pipeline. Downeast would comply with the DOT safety standards during construction and operation of the sendout pipeline, and we conclude that the risk of any incident along the proposed pipeline is low. As part of our evaluation of the LNG terminal, we performed technical review of the preliminary engineering design. Based on our analysis and recommendations presented in section 4.12, we conclude that sufficient layers of safeguards would be included in the facility designs to mitigate the potential for an incident that could impact the safety of the off-site public. DOT reviewed the data and methodology Downeast used to determine the design spills based on the flow from various leakage sources, including piping, containers, and equipment containing hazardous liquids. In a letter to FERC dated January 30, 2014, DOT stated it has no objection to Downeast's methodology for determining the candidate design spills used to establish the required siting for its proposed LNG import terminal. Based on the hazard area calculations performed by Downeast, we conclude that the Project would not result in significant public safety impacts.

On January 6, 2009, the Coast Guard issued an LOR and made an assessment in its WSR (Appendix B) that the Passamaquoddy Bay Waterway is suitable for the type and frequency of marine traffic associated with the proposed project, provided that all of the risk mitigation measures outlined in section 4.6 of the WSR are implemented by Downeast to the satisfaction of the Coast Guard Captain of the Port (COTP). The risk mitigation measures in the WSR also provide that Downeast must determine and comply with all applicable Canadian laws and regulations applicable to safe and secure navigation of maritime traffic, and customary international law. Under the Ports and Waterways Safety Act, the Magnuson Act, the Maritime Transportation Security Act of 2002, and the Safety and Accountability For Every Port Act, the COTP has the authority to prohibit LNG transfer or LNG vessel movements within his or her area of responsibility if he or she determines that such action is necessary to protect the waterway, port, or marine environment. If this project is approved and if appropriate resources are not in place prior to LNG vessel movement along the waterway, then the COTP would consider at that time what, if any, vessel traffic and/or facility control measures would be appropriate to adequately address navigational safety and maritime security considerations. As a result, we are recommending that Downeast should receive written authorization from the Director of OEP before commencement of service at the LNG terminal. Such authorization would only be granted following a determination by the Coast Guard that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by Downeast or other appropriate parties.

We are also recommending that Downeast develop an Emergency Response Plan in consultation with the Coast Guard and state and local agencies. Necessary security measures would further be incorporated into a Transit Management Plan that would clearly spell out roles, responsibilities, and specific procedures for LNG marine traffic transiting to the terminal, as well as for all agencies involved in implementing security and safety during operations. In addition, we are recommending that Downeast develop a Cost-Sharing Plan that identifies the mechanisms for funding all project-specific security/emergency management costs that would be imposed on state and local agencies.

## CONCLUSIONS AND RECOMMENDATIONS

We conclude that construction and operation of the Downeast LNG Project would result in some adverse environmental impacts. However, most of these impacts would be reduced to less-than-significant levels with the implementation of Downeast's proposed mitigation measures and the additional measures we are recommending in this EIS. Although many factors were considered in this determination, the primary reasons are:

- the Coast Guard's LOR states that the Passamaquoddy Bay Waterway is suitable for the type and frequency of marine traffic associated with the proposed project, provided that recommended risk mitigation measures outlined in section 4.6 of the WSR are fully implemented;

- adverse impacts on sensitive habitats and wildlife species would be avoided or minimized with incorporation of our recommendations;
- consultation required by Section 106 of the National Historic Preservation Act, and Section 7 of the Endangered Species Act, would be completed prior to construction;
- Downeast has committed to obtain all federal permits and authorizations and would obtain the necessary permits from the State of Maine;
- Downeast is continuing consultation with federal and state agencies to finalize a wetlands mitigation plan; develop a Prevention and Mitigation Manual to minimize adverse impacts on listed species, develop a final DWA mitigation package, determine seasonal or construction timing restrictions, design mitigation strategies to minimize acoustic harassment or harm to marine species, and develop a waterbody crossing schedule that identifies when trenching and blasting would occur;
- Downeast would implement its Plan*; Wetland and Waterbody Construction and Mitigation Procedures;* and *Soil Erosion and Sediment Control Guidelines* to minimize impacts on soils, wetlands and waterbodies; and
- environmental inspection and monitoring would ensure compliance with the mitigation measures that would become conditions if the project is authorized by the Commission.

**DOWNEAST LNG PROJECT**
**FINAL ENVIRONMENTAL IMPACT STATEMENT**
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## TECHNICAL ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| µg/kg | micrograms per kilogram |
| AAQS | ambient air quality standards |
| ACEEE | American Council for an Energy-Efficient Economy |
| ACHP | Advisory Council on Historic Preservation |
| Algonquin | Algonquin Gas Transmission, LLC |
| APE | area of potential effect |
| API | American Petroleum Institute |
| AQCRs | Air Quality Control Regions |
| AQRV | Air Quality Related Values |
| ASCE | American Society of Civil Engineers |
| ASME | American Society of Mechanical Engineers |
| ASMFC | Atlantic States Marine Fisheries Commission |
| ATBA | Area to be Avoided |
| ATV | all-terrain vehicle |
| ATWS | additional temporary workspace |
| AZMP | Atlantic Zone Monitoring Program |
| BA | Biological Assessment |
| BACT | Best Available Control Technology |
| BAQ | Bureau of Air Quality |
| Bcf | billion cubic feet |
| Bcfd | billion cubic feet per day |
| BEA | U.S. Bureau of Economic Analysis |
| bgs | below ground surface |
| BIA | Bureau of Indian Affairs |
| BLEVE | Boiling Liquid Expanding Vapor Explosion |
| BMPs | Best Management Practices |
| BOG | boil-off gas |
| Btu | British thermal units |
| Btu/hr-ft$^2$ | British thermal units per square foot per hour |
| BUD | Baileyville Utility District |
| °C | degrees Celsius |
| CAA | Clean Air Act |
| Calais LNG | Calais LNG Project Company LLC |
| Canadian Study | *A Study of the Anticipated Impacts from the Development of Liquefied Natural Gas Terminals on Passamaquoddy Bay* |
| CCME | Canadian Council of Ministers of the Environment |
| CEII | critical energy infrastructure information |
| CEPA | Canadian Environmental Protection Act |
| CEQ | Council on Environmental Quality |
| Certificate | Certificate of Public Convenience and Necessity |
| CFR | Code of Federal Regulations |
| CI | compression ignition |
| CMP | Central Maine Power |
| CO | carbon monoxide |

## TECHNICAL ACRONYMS AND ABBREVIATIONS – Cont'd

| | |
|---|---|
| $CO_2$ | carbon dioxide |
| Coast Guard | U.S. Coast Guard |
| COC | Certificate of Compliance |
| COE | U.S. Army Corps of Engineers |
| COI | Certificate of Inspection |
| CORMIX | Cornell Mixing Zone Expert System |
| COSEWIC | Committee on the Status of Endangered Wildlife in Canada |
| COTP | Captain of the Port |
| CSA | Canadian Standards Association |
| CWA | Clean Water Act |
| CZMA | Coastal Zone Management Act |
| CZMP | Coastal Zone Management Program |
| DAT | Deposition Analysis Threshold |
| dB | decibel |
| dBA | decibels on the A-weighted scale |
| dBL | decibels on the L-weighted scale |
| DCS | Distributed Control System |
| DE | Design Earthquake |
| DFO | Canadian Department of Fisheries and Oceans |
| DMA | dynamically managed area |
| DOD | U.S. Department of Defense |
| DOT | U.S. Department of Transportation |
| DPS | Distinct Population Segment |
| Dth/d | dekatherms per day |
| DWA | deer wintering areas |
| ECA | Emission Control Area |
| ECP | Environmental Control Plan |
| EEZ | economic exclusion zone |
| EFH | essential fish habitat |
| EGAD | Environmental and Groundwater Analysis Database |
| EI | Environmental Inspector |
| EIA | Energy Information Administration of the U.S. Department of Energy |
| EIS | Environmental Impact Statement |
| El | Elevation |
| EMEC | Eastern Maine Electric Cooperative |
| EPA | U.S. Environmental Protection Agency |
| EPAct | Energy Policy Act |
| ESA | Endangered Species Act |
| ESD | emergency shutdown |
| ERP | Emergency Response Plan |
| °F | degrees Fahrenheit |
| FDS | Fire Dynamics Simulator |
| FEED | Front-End Engineering Design |
| FEMA | Federal Emergency Management Agency |
| FLAG | Federal Land Managers Air Quality Related Values Workgroup |

## TECHNICAL ACRONYMS AND ABBREVIATIONS – Cont'd

| | |
|---|---|
| FMC | Fisheries Management Council |
| FMP | fisheries management plan |
| FMSC | Federal Maritime Security Coordinator |
| FPRF | Fire Protection Research Foundation |
| FR | Federal Register |
| FSO | Facility Security Officer |
| FSP | Facility Security Plan |
| FWS | U.S. Fish and Wildlife Service |
| GAO | U.S. Government Accountability Office |
| GHG | Greenhouse gases |
| GIS | Geographic Information Systems |
| gpm | gallons per minute |
| HAP | hazardous air pollutant |
| HAZOP | hazard and operability |
| HC | hydrocarbon |
| HCA | high consequence area |
| HDD | horizontal directional drill |
| HDMS | Hazard Detection and Mitigation System |
| HFO | heavy fuel oil |
| HIAAV | heat integrated ambient air vaporizers |
| HID | high-intensity discharge |
| HMSC | Huntsman Marine Science Center |
| hp | horse power |
| HTF | heat transfer fluid |
| Hz | hertz |
| IALA | International Association of Lighthouse Authorities |
| IBC | International Building Code |
| ICE | internal combustion engines |
| IGC Code | International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk |
| IMO | International Maritime Organization |
| Irving | Irving Oil Limited |
| ISA | International Society of Automation |
| ISPS | International Ship and Port Facility Security |
| IUCN | World Conservation Union |
| IWWH | inland waterfowl and wading bird habitat |
| JCR | jetty control room |
| kV | kilovolt |
| $L_{dn}$ | day-night sound level |
| $L_{eq(24)}$ | 24-hour equivalent sound level |
| LFL | lower flammability limit |
| LNG | liquefied natural gas |
| LOI | Letter of Intent |
| LOR | Letter of Recommendation |
| LOS | Level of Service |

## TECHNICAL ACRONYMS AND ABBREVIATIONS – Cont'd

| | |
|---|---|
| M&NE | Maritimes and Northeast Pipeline L.L.C. |
| m/s | meter per second |
| $m^3$ | cubic meters |
| $m^3$/hr | cubic meters per hour |
| MACT | Maximum Available Control Technology |
| Maine ASC | Maine Atlantic Salmon Commission |
| Maine BEP | Maine Board of Environmental Protection |
| Maine DECD | Maine Department of Economic and Community Development |
| Maine DEP | Maine Department of Environmental Protection |
| Maine DIFW | Maine Department of Inland Fisheries and Wildlife |
| Maine DMR | Maine Department of Marine Resources |
| Maine DOT | Maine Department of Transportation |
| Maine DWP | Maine Department of Health and Human Services, Division of Environmental Health, Drinking Water Program |
| Maine NAP | Maine Natural Areas Program |
| Maine PDES | Maine Pollutant Discharge Elimination System |
| Maine PUC | Maine Public Utilities Commission |
| Maine SPO | Maine State Planning Office |
| MARPOL | International Convention for the Prevention of Pollution from Ships |
| MBCA | Migratory Birds Convention Act |
| MBTA | Migratory Bird Treaty Act |
| MCE | Maximum Considered Earthquake |
| MCL | Maximum Contaminant Level |
| MCR | main control room |
| MDL | method detection limit |
| MEG | Maximum Exposure Guidelines |
| Memorandum | Memorandum of Understanding on Natural Gas Transportation Facilities |
| MEPC 59 | 59th session of the Marine Environmental Protection Committee |
| mgd | million gallons per day |
| MGS | Maine Geological Survey |
| MLLW | mean lower low water |
| MLV | mainline valves |
| MMBtuh | million British thermal units per hour |
| MMcfd | million cubic feet per day |
| MMI | Modified Mercalli Intensity |
| MMPA | Marine Mammal Protection Act |
| Moosehorn NWR | Moosehorn National Wildlife Refuge |
| MOPU | mobile offshore production unit |
| MP | milepost |
| mph | miles per hour |
| MRSA | Maine Revised Statute Annotated |
| MSA | Magnuson-Stevens Fishery Conservation and Management Act |
| MSL | mean sea level |
| MTSA | Maritime Transportation Security Act of 2002 |

## TECHNICAL ACRONYMS AND ABBREVIATIONS – Cont'd

| | |
|---|---|
| $N_2O$ | nitrous oxide |
| NAAQS | national ambient air quality standards |
| NARWC | North Atlantic Right Whale Consortium |
| NAVD88 | North American Vertical Datum of 1988 |
| NAVTEX | Navigational Telex |
| NCA | National Climate Assessment |
| NEC | National Electrical Code |
| NEPA | National Environmental Policy Act of 1969 |
| NESHAPs | National Emissions Standards for Hazardous Air Pollutants |
| NFPA | National Fire Protection Association |
| NGA | Natural Gas Act |
| NHPA | National Historic Preservation Act |
| NIST | National Institute of Standards and Technology |
| NOA | Notice of Availability |
| NOAA Fisheries | National Oceanic and Atmospheric Administration, National Marine Fisheries Service |
| NOI | Notice of Intent |
| Northeast Gateway | Northeast Gateway Energy Bridge |
| NOx | nitrogen oxides |
| NPDES | National Pollutant Discharge Elimination System |
| NPS | National Park Service |
| NRCS | Natural Resources Conservation Service |
| NRHP | National Register of Historic Places |
| NRI | National Rivers Inventory |
| NRPA | Maine Natural Resources Protection Act |
| NSA | noise sensitive area |
| NSPS | New Source Performance Standards |
| NSR | New Source Review |
| NVIC | Navigation and Vessel Inspection Circular |
| NWI | National Wetlands Inventory |
| $O_3$ | ozone |
| OBE | operating basis earthquake |
| OBIS | Ocean Biogeography Information System |
| OEP | FERC Office of Energy Projects |
| OPS | Office of Pipeline Safety |
| ORPC | Ocean Renewable Power Company |
| ORV | open rack vaporizer |
| OSHA | Occupational Safety and Health Administration |
| OTR | Ozone Transport Region |
| P&ID | piping and instrumentation diagrams |
| PAH | polyaromatic hydrocarbon |
| PAWSA | Ports and Waterways Safety Assessment |
| Pb | lead |
| PCB | polychlorinated biphenyl |
| PCDD | polychlorinated dibenzo-p-dioxin |

## TECHNICAL ACRONYMS AND ABBREVIATIONS – Cont'd

| | |
|---|---|
| PCDF | polychlorinated dibenzofuran |
| PFD | process flow diagram |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PI | Point of Inflection |
| PIC | person in charge |
| Plan | Upland Erosion Control, Revegetation and Maintenance Plan |
| PM | particulate matter |
| $PM_{10}$ | particles with an aerodynamic diameter less than or equal to 10 microns |
| $PM_{2.5}$ | particles with an aerodynamic diameter less than or equal to 2.5 microns |
| PNGTS | Portland Natural Gas Transmission System |
| ppm | parts per million |
| Procedures | Wetland and Waterbody Construction and Mitigation Procedures |
| PSD | Prevention of Significant Deterioration |
| psi | pounds per square inch |
| psig | pounds per square inch gauge |
| PTE | potential to emit |
| QA/QC | quality assurance/quality control |
| Quest | Quest Consultants, Inc. |
| RCRA | Resource Conservation and Recovery Act |
| Repsol | Repsol Energy North America Corporation |
| RMP | Risk Management Plan |
| RMS | root mean square |
| RO | reverse osmosis |
| Roadmap | LNG Regulatory Roadmap |
| RPT | rapid phase transition |
| RSS | Regional Site Selection |
| Sandia | Sandia National Laboratories |
| SARA | Species at Risk Act |
| SCADA | Supervisory Control and Data Acquisition |
| SCV | submerged combustion vaporizer |
| SHPO | Maine State Historic Preservation Office |
| SILs | Significant Impact Levels |
| SIP | State Implementation Plan |
| SIS | Safety Instrumentation System |
| $SO_2$ | sulfur dioxide |
| SOLAS | International Convention for the Safety of Life at Sea |
| SOPEP | Shipboard Oil Pollution Emergency Plan |
| SPA | Saguenay Port Authority |
| SPCC Plan | Spill Prevention, Control and Countermeasure Plan |
| SRV | shuttle regasification vessel |
| SSE | safe shutdown earthquake |
| SSURGO | Soil Survey Geographic (NRCS) |
| STCW | International Convention Standards of Training, Certification and Watch Keeping for Seafarers |
| STV | shell and tube vaporizer |

## TECHNICAL ACRONYMS AND ABBREVIATIONS – Cont'd

| | |
|---|---|
| SVOC | semivolatile organic compound |
| SVP | significant vernal pools |
| SWPPP | Stormwater Pollution Prevention Plan |
| Tennessee Gas | Tennessee Gas Pipeline |
| THPO | Tribal Historic Preservation Officer |
| Tidewalker | Tidewalker Tidal Energy Project |
| TKN | total Kjeldahl nitrogen |
| TMP | Transit Management Plan |
| TNA | Three Nation Alliance |
| tpy | tons per year |
| TQM | Trans Quebec and Maritimes |
| Tractabel | Tractabel LNG North America, L.L.C. |
| TWWH | tidal waterfowl and wading bird habitat |
| UFL | upper flammability limit |
| USCB | U.S. Census Bureau |
| USC | United States Code |
| USDA | U.S. Department of Agriculture |
| USDOI | U.S. Department of Interior |
| USGCRP | United States Global Change Research Program |
| VGP | Vessel General Permit |
| USGS | United States Geological Survey |
| VOC | volatile organic compound |
| VTS | Vessel Traffic Scheme |
| WPA | wellhead protection area |
| WSA | Waterway Suitability Assessment |
| WSR | Waterway Suitability Report |
| μPa | micro-Pascal |

# 1.0 INTRODUCTION

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared this final Environmental Impact Statement (EIS) for public review and comment to assess the potential environmental effects that may occur as a result of the construction and operation of the proposed liquefied natural gas (LNG) import terminal (LNG terminal) and associated natural gas pipeline (sendout pipeline) in Washington County, Maine (collectively referred to as the Downeast LNG Project). This final EIS will be used by the FERC in its decision-making process to determine whether or not to authorize the project.

| |
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| The vertical line in the margin identifies text that has been modified in this final EIS and differs substantially from the corresponding text in the draft EIS. |

On December 22, 2006, Downeast LNG, Inc. (Downeast LNG) filed an application with the FERC, in Docket No. CP07-52-000, under Section 3(a) of the Natural Gas Act (NGA) and Part 153 and 380 of the Commission's regulations. Also on December 22, 2006, Downeast Pipeline, LLC (Downeast Pipeline) filed: (1) an application in Docket No. CP07-53-000 for a Certificate of Public Convenience and Necessity (Certificate): (i) authorizing Downeast Pipeline to construct, own, and operate the Downeast Pipeline under Section 7 of the NGA and Part 157 of the Commission's regulations, (ii) approving the pro forma Tariff submitted as Exhibit P of the application, and (iii) approving the proposed initial rates for pipeline transportation services; (2) an application in Docket No. CP07-54-000 for a blanket certificate authorizing Downeast Pipeline to engage in certain self-implementing routine activities under Part 157 Subpart F of the Commission's regulations; and (3) an application in Docket No. CP07-55-000 for a blanket certificate authorizing Downeast Pipeline to transport natural gas, on an open access and self-implementing basis, under Part 284 Subpart G of the Commission's regulations. These applications were noticed in the *Federal Register* (FR) on December 29, 2006. Downeast Pipeline is a wholly owned subsidiary of Downeast LNG (hereafter collectively referred to as Downeast).

On January 16, 2008, Downeast filed an amendment to its application in Docket No. CP07-53-001 to modify the pipeline route filed in Docket No. CP07-53-000 to avoid crossing the Moosehorn National Wildlife Refuge (Moosehorn NWR), as well as four route deviations in other locations. This application was noticed in the FR on February 13, 2008.

In Docket No. CP07-52-000, Downeast proposes to import, store, and vaporize LNG and sendout natural gas on average about 500 million cubic feet per day (MMcfd) with peak deliveries of 625 MMcfd at a terminal facility to be located on the south side of Mill Cove in the Town of Robbinston, near the confluence of Passamaquoddy Bay and the St. Croix River in Washington County, Maine. The proposed terminal site is bounded by Mill Cove to the north, U.S. Route 1 and rural residential and forested areas to the west, forested land to the south, and Passamaquoddy Bay to the east. Downeast requests Commission authorization to construct and operate a marine LNG terminal, including:

- a 3,862-foot-long, 37-foot-wide pier with a single berth that would accommodate LNG vessels with cargo capacities ranging from 70,000 to 165,000 cubic meters ($m^3$);
- three 16-inch-diameter unloading arms and one vapor return line on the unloading platform, with an unloading capacity rate of 14,000 $m^3$ of LNG per hour;
- one 3,862-foot-long, 36-inch-diameter single-walled stainless steel insulated transfer pipeline;

- two insulated LNG storage tanks, each with a nominal usable storage capacity of 160,000 $m^3$;
- two fully submerged, low pressure cryogenic transfer pumps, each rated for 4,600 gallons per minute (gpm);
- boil-off gas (BOG) recovery system consisting of three BOG compressors, two vapor blowers, and direct contact re-condenser to re-liquefy the BOG;
- four submerged combustion vaporizers (SCV) to re-vaporize LNG to natural gas;
- electrical power distribution, including power substations and transformers with total connected load at approximately 10.8 megawatts;
- ancillary terminal facilities, including control room, maintenance shop, warehouse, office, security, and safety systems;
- measurement controls and natural gas metering facilities; and
- a comprehensive hazard monitoring system incorporating flammable gas detectors, high and low temperature detectors, smoke detectors, and local emergency shutdown controls.

In Docket Nos. CP07-53-000 and CP07-53-001 Downeast requested Commission authorization to construct and operate a natural gas sendout pipeline capable of transporting a maximum of 625 MMcfd, with an expected average throughput of 500 MMcfd. Downeast's facilities would consist of:

- a 29.8-mile-long, 30-inch-diameter natural gas pipeline;
- natural gas metering facilities located at the LNG terminal site;
- pigging facilities[2]; and
- three mainline block valves.

Figure 1-1 shows the general location of the proposed facilities.

The proposed Downeast sendout pipeline would transport natural gas from the LNG terminal to an interconnect point with Maritimes and Northeast Pipeline's L.L.C. (M&NE) existing pipeline system near the town of Baileyville, Maine. Downeast's project would transport between 500 and 625 MMcfd. M&NE's existing system is capable of transporting about 800 MMcfd. We[3] originally considered an expansion of the M&NE system in our draft EIS (called the M&NE Downstream Expansion); however, we have since determined that M&NE's existing system would be capable of transporting the additional gas volume proposed by Downeast, with some major changes in gas flow. Market conditions and new gas supplies, principally from shale gas sources, could change the economic landscape for gas supplies and the direction of gas flows on the M&NE system. Further, M&NE has not proposed an expansion of its existing system to transport the gas from Downeast's proposed facilities, and our analysis of an expansion at this time would be presumptive and premature. Additionally, M&NE must file an application with the FERC for authorization to construct any expansion facilities. The FERC would conduct a full environmental analysis of the proposal, including preparation of an environmental assessment or EIS, before the Commission would consider authorizing M&NE to construct any downstream facilities. Therefore, we have eliminated the discussion of M&NE's facilities, which was included in the draft EIS, from this final EIS.

[2] A pig is an internal tool that can be used to clean and dry a pipeline and/or to inspect it for damage or corrosion.
[3] "We," "us," and "our" refer to the environmental staff of the Federal Energy Regulatory Commission's Office of Energy Projects (OEP).

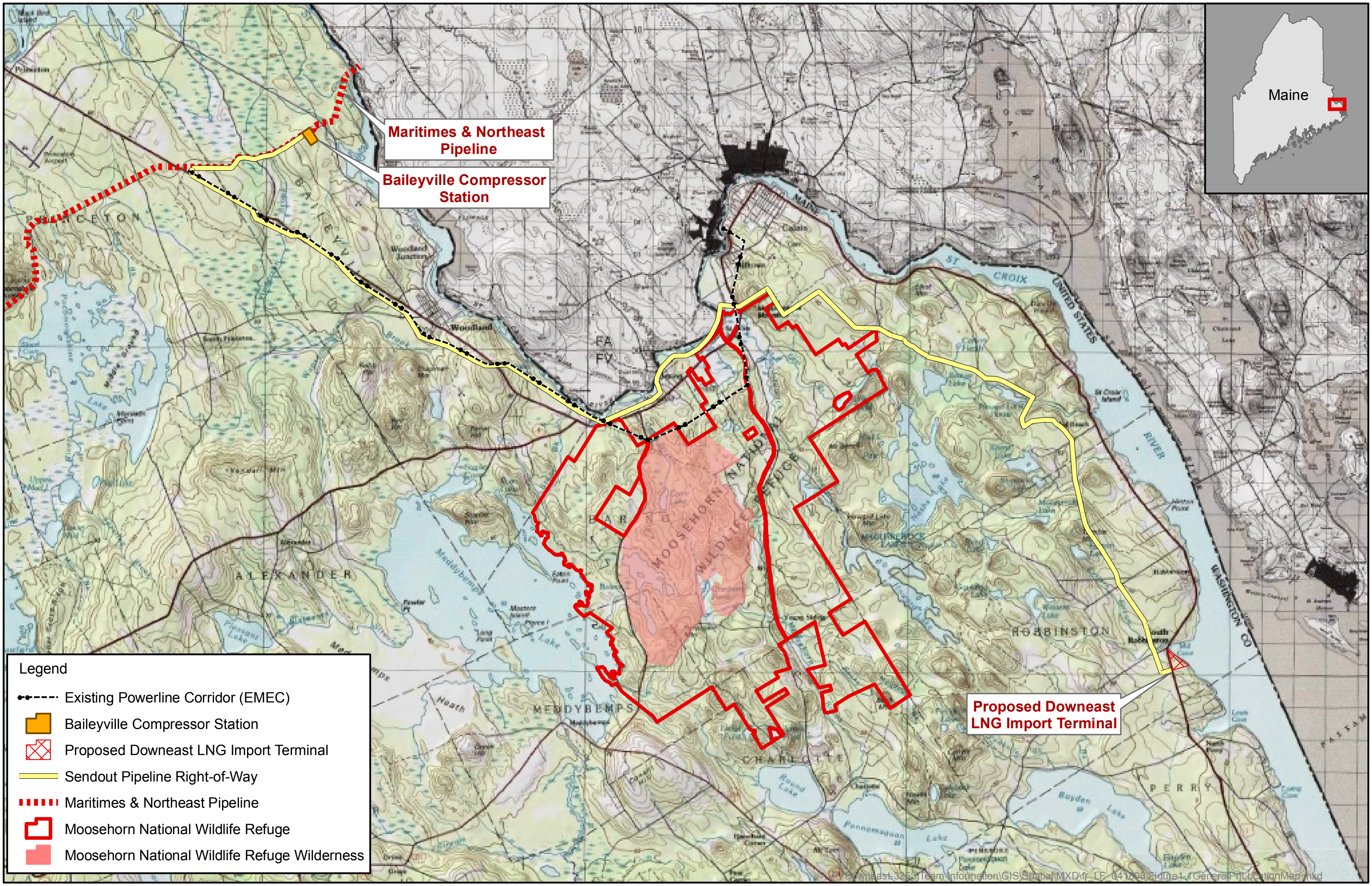


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**Figure 1-1**
**Downeast LNG Project**
**General Project Location Map**

0 0.5 1 2 3 4 Miles

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## 1.1 PROJECT PURPOSE AND NEED

The purpose for the Downeast LNG Project, as summarized below, is defined by Downeast. Need is not an environmental issue to be addressed at length in this document. The Commission will more fully consider the need for the project when making its decision on whether the project is consistent with the public interest in meeting the projected energy demands of the region. The FERC will use the final EIS as an element in its review of Downeast's application. After the final EIS is released, the Commission will determine whether the project should be authorized. The EIS and mitigation development discussed herein will be important factors in this final determination. This EIS includes a short discussion of the project purpose and need to satisfy the requirements of the Council on Environmental Quality (CEQ) regulations for implementing the National Environmental Policy Act of 1969 (NEPA), which state that an EIS should only "briefly specify the underlying purpose and need" for a proposed project (40 Code of Federal Regulations [CFR] 1502.13).

We received comments on the draft EIS from Ronald S. Rosenfeld, M.D., the Conservation Law Foundation, the U.S. Army Corps of Engineers (COE), and the U.S. Department of the Interior, Office of Environmental Quality and Compliance, among others, regarding the sufficiency of this section and current forecasts of future demand for natural gas. As stated above, need is not an environmental issue to be addressed at length in this document. The Commission will more fully consider the need for the project when making its decision on whether the project is consistent with the public interest. The Commission's Certificate Policy Statement[4] provides guidance as to how the Commission evaluates proposals for authorizing new construction, and establishes criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest.

Downeast stated in its application that the purpose of the project is to establish an LNG marine terminal in New England capable of receiving imported LNG from LNG vessels, storing, and regasifying the LNG at an average sendout rate of 500 MMcfd. The terminal would provide an additional supply source of natural gas in the New England region (Maine, Massachusetts, New Hampshire, Vermont, Connecticut, and Rhode Island). The proposed storage tanks at the LNG facility would provide an additional 6.6 billion cubic feet (Bcf) of gas storage capacity in the region. Downeast conducted a non-binding open season that commenced on November 3, 2008 and concluded on December 2, 2008. Downeast's affiliate, Downeast LNG Trading, LLC submitted the only bid through the open season process for 500 MMcfd of firm transportation service.

Under section 3 of the NGA, the Commission grants authorization for proposed LNG import terminals unless it finds that the proposed facilities will not be consistent with the public interest. Under section 7 of the NGA, the Commission determines whether interstate natural gas transportation facilities are in the public convenience and necessity and, if so, grants a Certificate to construct and operate them. The Commission bases its decision on technical competence, financing, rates, market demand, gas supply, environmental impact, long-term feasibility, and other issues concerning a proposed project.

[4] Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC ¶61,227 (1999), order on clarification, 90 FERC ¶61,128 (2000), order on clarification, 92 FERC ¶61,094 (2000) (Certificate Policy Statement).

## 1.2 PURPOSE AND SCOPE OF THIS ENVIRONMENTAL IMPACT STATEMENT

The FERC is the federal agency responsible for authorizing applications to construct and operate onshore LNG import and interstate natural gas transmission facilities. The U.S. Department of Transportation (DOT) is a cooperating agency to the FERC, serving as a subject matter expert on its federal safety standards for siting, construction, operation, and maintenance of onshore LNG facilities codified in 49 CFR 193. The DOT does not issue a permit or license but, as a cooperating agency, assists FERC staff in evaluating whether an applicant's proposed design would meet the DOT requirements. The U.S. Coast Guard (Coast Guard) is a cooperating agency to the FERC, serving as a subject matter expert for, and providing recommendations on the maritime safety and security aspects of the project. The Coast Guard does not issue a permit, license, or order in this context, and is responsible for assessing the suitability of the waterway and issuing a Letter of Recommendation (LOR). That LOR may be considered by FERC (as the lead agency) to help assist with their decision concerning approval of the project. The FERC is the lead federal agency for the preparation of this EIS in compliance with the requirements of the NEPA, the CEQ regulations for implementing the NEPA (40 CFR 1500-1508), and the FERC's regulations for implementing the NEPA (18 CFR 380). The FERC will use this EIS as an element in its review of Downeast's applications to determine whether to authorize the LNG project. The Commission will consider the environmental issues, including our recommended mitigation measures, as well as non-environmental issues. Final authorization will be granted only if the Commission finds that the proposed LNG project is in the public interest. The environmental impact assessment and mitigation discussed in this EIS are important factors in this final determination.

The Coast Guard; COE; DOT; National Oceanic and Atmospheric Administration, National Marine Fisheries Service (NOAA Fisheries); U.S. Environmental Protection Agency (EPA); and the Maine Department of Environmental Protection (Maine DEP) are the cooperating agencies for the development of this EIS. A cooperating agency has jurisdiction by law or special expertise with respect to environmental impacts involved with the proposal and is involved in the NEPA analysis.

This final EIS was prepared to respond to comments received on the draft EIS. Our principal purposes in preparing this EIS are to:

- identify and assess potential impacts on the environment that would result from the implementation of the proposed action;
- identify and assess reasonable alternatives to the proposed action that would avoid or minimize adverse effects on the human environment;
- identify and recommend specific mitigation measures to minimize environmental impacts and that protect, restore, and enhance the environment;
- fully inform and support decisions by the public agencies responsible for permitting the project that are based on understanding environmental consequences; and
- facilitate public involvement in identifying significant environmental impacts.

Our analysis in this EIS focuses on facilities that are under the FERC's jurisdiction in Downeast's applications (i.e., the proposed LNG terminal and 29.8 miles of sendout pipeline).

One nonjurisdictional electric power supply facility would also be constructed in association with the project (see section 2.9 of this EIS).

The topics addressed in this EIS include alternatives; geology; soils and sediments; water use and quality; wetlands; vegetation; wildlife; aquatic resources including essential fish habitat (EFH); threatened, endangered, and special status species; land use, recreation, and visual resources; socioeconomics; transportation and traffic; cultural resources; air quality and noise; reliability and safety; and cumulative impacts. This EIS describes the affected environment as it currently exists, discusses the environmental consequences of the proposed project, and compares the project's potential impacts to the potential impacts of other alternatives. This EIS also presents our conclusions and recommended mitigation measures.

## 1.3 PERMITS, APPROVALS, AND REGULATORY REVIEWS

As the lead federal agency for the Downeast LNG Project, the FERC is required to comply with Section 7 of the Endangered Species Act of 1973, the Magnuson-Stevens Fishery Conservation and Management Act of 1976, Marine Mammal Protection Act of 1972, Section 106 of the National Historic Preservation Act of 1966, and Section 307 of the Coastal Zone Management Act of 1972. Each of these statutes has been taken into account in the preparation of this document.

The Coast Guard exercises regulatory authority over LNG facilities that affect the safety and security of port areas and navigable waterways under Executive Order 10173; the Magnuson Act (50 United States Code [USC] Section 191); the Ports and Waterways Safety Act of 1972, as amended (33 USC Section 1221 et seq.); and the Maritime Transportation Security Act of 2002 (46 USC Section 701). The Coast Guard is responsible for matters related to navigation safety, vessel engineering and safety standards, and all matters pertaining to the safety of the facilities or equipment located in or adjacent to navigable waters up to the last valve immediately before the receiving LNG tanks. The Coast Guard also has authority for LNG facility security plan review, approval, and compliance verification as provided in Title 33 CFR Part 105, and siting as it pertains to the management of marine traffic in and around the LNG facility.

As required by its regulations, the Coast Guard is responsible for issuing an LOR as to the suitability of the waterway for LNG marine traffic. The LOR was based on the following criteria which are discussed further throughout this EIS in the appropriate resource sections:

- implications to maritime and port security;
- density and character of marine traffic;
- locks, bridges, and other man-made obstructions in the waterway;
- environmental effects of LNG vessels during transit from open water to the facility; and
- the following factors adjacent to the facility:
    - depth of water
    - tidal range
    - protection from high seas
    - natural hazards, including reefs, rocks, and sandbars
    - underwater obstructions, such as pipes and cables
    - distance of berthed vessels from the channel
    - width of the channel

On June 14, 2005, the Coast Guard published the *Navigation and Vessel Inspection Circular (*NVIC*) 05-05*. The purpose of NVIC 05-05 was to provide the Coast Guard Captain of the Ports (COTPs)/Federal Maritime Security Coordinators (FMSCs), members of the LNG industry, and port stakeholders with guidance on assessing the suitability of a waterway for LNG marine traffic. The assessment should take into account conventional navigation safety/waterway management issues contemplated by the existing Letter of Intent (LOI)/LOR process, and, in addition, should comprehensively treat maritime security. Since the publication of NVIC 05-05 and NVIC 05-08 the Coast Guard has issued an updated NVIC 01-11, which revised some of the previous guidance. Specifically, the Coast Guard revised the format of the LOR to conform to its intended effect of being a recommendation to FERC as to the suitability of the waterway. The Coast Guard also added guidance on release of the LOR and message management, and provided an updated template for the LOR analysis. Furthermore, NVIC 01-11 clarified the timing and scoping of the process that is necessary to ensure that full consideration is given to safety and security of the port, the facility, and the vessels transporting the LNG. As the Downeast LNG proposal originated under NVIC 05-05, the Coast Guard's assessment for this proposal was developed under NVIC 05-05, NVIC 05-08, and NVIC 01-11. In order to avoid confusion, we note that the Coast Guard has decided to refer to its final assessment for the Downeast LNG proposal as the *Downeast LNG Waterway Suitability Report* (WSR) although this term has been eliminated in the new NVIC and replaced with "Letter of Recommendation Analysis." In addition, the Coast Guard has updated the regulations within 33 CFR Part 127. The Coast Guard notes that Downeast should consult these updated regulations when constructing a waterfront facility handling LNG. See section 4.12.5 of this EIS for additional discussion of marine safety.

Downeast submitted its preliminary Waterway Suitability Assessment (WSA) to the Coast Guard on December 21, 2005, and the Follow-on WSA was submitted on December 19, 2006. The COTP Sector Northern New England reviewed the WSA and completed a WSR that is included as Appendix B of this EIS. As part of the WSR dated January 6, 2009, the COTP Sector Northern New England assessed that the waterway for LNG marine traffic is suitable for the type and frequency of LNG marine traffic associated with the proposed project, provided that the risk mitigation measures outlined in section 4.6 of the WSR are fully implemented. The WSR and risk reduction measures are described further in section 4.12.

*<u>Endangered Species Act (ESA)</u>*

Section 7 of the ESA, as amended, states that any project authorized, funded, or conducted by any federal agency (e.g., FERC) should not "…jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined…to be critical…" (16 USC Section 1536(a)(2)(1988)). The FERC, or Downeast as a non-federal party, is required to consult with the U.S. Fish and Wildlife Service (FWS) and NOAA Fisheries to determine whether any federally listed or proposed endangered or threatened species or their designated critical habitat occur in the vicinity of the proposed project. If, upon review of existing data or data provided by the applicant, the FERC determines that these species or habitats may be affected by the proposed LNG project, the FERC is required to prepare a Biological Assessment (BA) to identify the nature and extent of adverse impact, and to recommend measures that would avoid the habitat and/or species, or that would reduce potential impacts to acceptable levels or as appropriate carrying out conservation programs for the listed species. If, however, the FERC determines that no federally listed or proposed endangered or threatened species or their designated critical habitat would be affected by the proposed project, no further action is necessary under the ESA. FERC has prepared a BA, which is included as Appendix C.

*<u>Magnuson-Stevens Fishery Conservation and Management Act (MSA)</u>*

The MSA, as amended by the Sustainable Fisheries Act of 1996 (Public Law 104-267), established procedures designed to identify, conserve, and enhance essential fish habitat (EFH) for those species regulated under a federal fisheries management plan. The MSA requires federal agencies to consult with NOAA Fisheries on all actions or proposed actions authorized, funded, or undertaken by the agency that may adversely affect EFH (MSA Section 305(b)(2)). Although absolute criteria have not been established for conducting EFH consultations, NOAA Fisheries recommends consolidating EFH consultations with interagency coordination procedures required by other statutes such as the NEPA, the Fish and Wildlife Coordination Act, or the ESA (50 CFR 600.920(e)) in order to reduce duplication and improve efficiency. As part of the consultation process, the FERC has evaluated potential impacts on EFH in this EIS (see section 4.5.3 and Appendix G.

*<u>Marine Mammal Protection Act (MMPA)</u>*

The MMPA of 1972 prohibits, with certain exceptions, the take of marine mammals in U.S. waters and by U.S. citizens on the high seas, and the importation of marine mammals and marine mammal products into the United States. Congress amended the MMPA in 1994 to provide for certain exceptions to the take prohibitions, including a program to authorize and control the taking of marine mammals incidental to commercial fishing operations; preparation of stock assessments for all marine mammal stocks in waters under U.S. jurisdiction; and studies of pinniped-fishery interactions. The Secretary of the NOAA Fisheries, in consultation with any other federal agency (e.g., FERC) to the extent that such agency may be affected, prescribes regulations as are necessary and appropriate to carry out the purposes of the MMPA (16 USC 1382 Section 112 (a)). See section 4.5.2 of this EIS for a discussion on marine mammals.

*<u>National Historic Preservation Act (NHPA)</u>*

Section 106 of the NHPA, as amended, requires the FERC to take into account the effects of its undertakings on historic properties, and provide the Advisory Council on Historic Preservation (ACHP) an opportunity to comment. Historic properties include prehistoric or historic sites, and districts, buildings, structures, objects, or properties of traditional religious or cultural importance that are listed or eligible for listing on the National Register of Historic Places (NRHP). FERC has requested that Downeast, as a non-federal party, assist in meeting FERC's obligation under Section 106 by preparing the necessary information and analyses as required by the ACHP procedures in 36 CFR 800. See section 4.10 of this EIS for the status of this review.

*<u>Coastal Zone Management Act (CZMA)</u>*

The CZMA calls for the "effective management, beneficial use, protection, and development" of the nation's coastal zone and promotes active state involvement in achieving those goals. As a means to reach those goals, the CZMA requires participating states to develop management programs that demonstrate how these states will meet their obligations and responsibilities in managing their coastal areas. In the state of Maine, the Maine Department of Agriculture is the agency responsible for administering its Coastal Zone Management Program (CZMP). Because

Section 307 of the CZMA requires federal agency activities to be consistent to the maximum extent practicable with the enforceable policies of a management program, the FERC requires that Downeast seek a determination of consistency with Maine's CZMP for construction and operation of the proposed facility and associated vessel operations. See section 4.7.5 of this EIS for additional discussion of the Maine CZMP and the status of the consistency review.

*Other Permits, Approvals, and Consultations*

In addition to FERC, other federal agencies have responsibilities for issuing permits or approvals to comply with various federal laws and regulations. For example, the COE would issue permits under the Clean Water Act (CWA) and the Rivers and Harbors Act; and the EPA has regulatory authority under the CWA and the Clean Air Act (CAA). Several Maine state agencies have delegated responsibilities under the CWA, CAA, and CZMA.

The Energy Policy Act (EPAct) of 2005 and Section 3 of the NGA require that FERC consult with the U.S. Department of Defense (DOD) to determine whether or not proposed projects would affect training or activities on military installations. In letters dated March 24, 2006 to the DOD, Army, COE, Navy, and Air Force at the Pentagon, we requested to be informed of any defense or military establishments in the project area that may be affected by the project. We did not receive a response to those letters. The FERC sent an additional letter to the DOD on February 12, 2014 with the Draft EIS and Supplemental Draft EIS.

In addition, the NGA, as modified by the EPAct, requires that the Commission consult with the state in which an LNG terminal is proposed to be located regarding state and local safety matters. On December 7, 2005, the Governor of Maine designated the Maine State Planning Office (Maine SPO) as the state agency that FERC should consult with on safety and siting matters for the Downeast LNG Project. The Maine SPO submitted its Safety Advisory Report to FERC on January 19, 2007. In the report, the Maine SPO addressed state and local considerations for the project developed in consultation with the Maine Emergency Management Agency, Maine State Police, Office of State Fire Marshal, Maine Marine Patrol, and Maine DEP's Oil and Hazardous Materials Division. In 2012, the Maine SPO was eliminated; the Maine DEP now serves as the contact for LNG projects for the State of Maine.

The EPAct also stipulates that, before the Commission may issue an order authorizing an LNG terminal, it must "review and respond specifically" to the safety matters raised by the state agency designated as the lead for the state and local safety matters. Appendix D presents FERC's response to the Maine SPO Safety Advisory Report for the Downeast LNG Project.

Major permits, approvals, and consultations that Downeast has agreed to obtain for the Downeast LNG Project are identified in table 1.3-1. The FERC encourages cooperation between applicants and state and local authorities, but this does not mean that state and local agencies, through applications of state and local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by the FERC. Any state or local permits issued with respect to jurisdictional facilities must be consistent with the conditions of any authorization issued by the

FERC.[5] Downeast would be responsible for obtaining all permits and approvals to construct and operate the proposed project, regardless of whether they appear in this table or not.

TABLE 1.3-1

**Major Permits, Approvals, and Consultations for the Downeast LNG Project**

| Agency | Permits/Approvals/Consultations | Anticipated Application Filing/Consultation Date |
|---|---|---|
| **FEDERAL** | | |
| Federal Energy Regulatory Commission (FERC) | Authorization under Sections 3a (Approval of Place of Import for Natural Gas) and 7c (Certificate of Public Convenience and Necessity) of the Natural Gas Act | Downeast filed applications on December 22, 2006 and January 16, 2008. |
| Advisory Council on Historic Preservation (ACHP) | Opportunity to comment on the project under Section 106 of the NHPA | Pending completion of surveys and evaluations identifying historic properties, and consultations with the State Historic Preservation Office (SHPO) and Tribal Historic Preservation Office (THPO). |
| U.S. Army Corps of Engineers (COE) | Authorization for activities that could affect the course, condition, or capacity of navigable waters under Section 10 of the Rivers and Harbors Act of 1899 | Preliminary permit application submitted on December 20, 2006. Will submit revised final permit application following issuance of final EIS. |
| | Authorization to discharge dredged or fill material into waters of the United States under Section 404 of the Clean Water Act | Preliminary permit application submitted on December 20, 2006. Will submit revised final permit application following issuance of final EIS. |
| U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service (NOAA Fisheries) | Consultation with NOAA Fisheries Protected Resources Division regarding compliance with Section 7 of the ESA and the MMPA | Downeast submitted Consultation Request Letter on February 21, 2006; and January 7, 2008 for the amended pipeline route. FERC's BA included as Appendix C of this EIS. |
| | Consultation with NOAA Fisheries Habitat Conservation Division on threatened and endangered aquatic species, EFH conservation recommendations, and compliance with Section 305 of the MSA | FERC's EFH Assessment is included in Appendix G of this EIS. |
| U.S. Department of Homeland Security U.S. Coast Guard (Coast Guard) | 33 CFR Part 127<br>Issue Letter of Recommendation, Waterfront Facilities Handling LNG and Liquefied Hazardous Gas, and Operational Plan | Downeast submitted an initial LOI to the Coast Guard on December 20, 2005 and amendments to the LOI on January 6 and February 8, 2006; and filed a preliminary WSA on December 21, 2005 with a follow-on WSA on December 19, 2006. The Coast Guard issued its LOR and WSR on January 6, 2009, assessing the waterway to be suitable provided risk mitigation measures are implemented. Downeast conducted an annual review of its WSA and provided substantiation to the Coast Guard on September 13, 2011 and January 3, 2014. On November 10, 2011 and February 24, 2014, the Coast Guard responded that the updates did not affect the suitability of the waterway. |
| | Permission to Establish Aids to Navigation (33 CFR Part 66, 14; U.S.C. §§ 84-86) | To be submitted following conclusion of primary state and federal permitting (anticipated 2014). |
| | Spill Prevention and Spill Response Plan under 33 U.S.C. § 1321 | Draft Plan submitted on December 22, 2006. |

[5] See, e.g., Schneidewind v. ANR Pipeline Co., 485 U.S. 293 (1988); National Fuel Gas Supply v. Public Service Commission, 894 F.2d 571 (2n Cir. 1990); and Iroquois Gas Transmission System, L.P., et al., 52 FERC 61,091 (1990) and 59 FERC 61,094 (1992).

TABLE 1.3-1

**Major Permits, Approvals, and Consultations for the Downeast LNG Project**

| Agency | Permits/Approvals/Consultations | Anticipated Application Filing/Consultation Date |
|---|---|---|
| U.S. Department of Defense (DOD) | Consultation as required by Section 311 of the Energy Policy Act of 2005 and Section 3 of the Natural Gas Act | FERC consultation on March 24, 2006 and February 12, 2014 with the DOD regarding information on project effects to military installations. (Awaiting response). |
| U.S. Department of the Interior, Fish and Wildlife Service (FWS) | Section 7 of the ESA<br>Consultation regarding effects on threatened and endangered species | Downeast submitted Consultation Request Letter on February 21, 2006; and January 7, 2008 for the amended pipeline route. FERC's BA included as Appendix C of this EIS. |
| | Incidental Take Permit under Migratory Bird Act and Endangered Species Act | Need for incidental take permit to be determined. |
| U.S. Department of Transportation (DOT) | 49 CFR 192<br>Evaluate compliance with federal safety standards; encroachment permits for crossing of federal highways | Permit application to be submitted during construction. |
| **STATE** | | |
| Maine Department of Conservation – Bureau of Parks and Land; Maine Natural Areas Program | Submerged lands lease and easement | To be submitted in conjunction with Maine Department of Environmental Protection (DEP) Permitting anticipated 2014. |
| | Consultation and review on other Maine State permits | Consultation Request Letter submitted on February 21, 2006. |
| Maine Forest Service | Timber Harvest/Management Plan; Consultation on other State permits | To be submitted in conjunction with Maine DEP Permitting anticipated 2014. |
| Maine DEP | Maine Mandatory Shoreland Zoning Act | Application approved on February 16, 2006. |
| Bureau of Land & Water Quality (Maine DEP) | 401 Water Quality Certificate<br>Natural Resources Protection Act<br>Site Location of Development Act<br>Air Emissions License | To be submitted in conjunction with Maine DEP Permitting anticipated 2014. |
| | Maine Construction General Permit (construction stormwater discharges) and Discharge License for Subsurface Waste Water Disposal System (septic tank leach field) | To be submitted prior to construction. |
| | Multisector Permit and Waste Discharge (Maine Pollutant Discharge Elimination System [Maine PDES]) Permit | To be submitted prior to operation. |
| Department of Marine Services (Maine DEP) | Consultation/Review on Other Maine State Permits | Consultation Request Letter submitted on February 21, 2006. |
| Maine Department of Agriculture, Conservation and Forestry | Section 307 of the CZMA<br>Determine coastal zone management consistency | To be submitted in conjunction with Maine State DEP Permitting anticipated 2014. |
| Maine Historic Preservation Office (SHPO) | Section 106 of the NHPA<br>Consultation regarding NRHP eligibility and project effects. | Downeast submitted revised cultural resources survey reports to the SHPO in October 2006. SHPO provided reviews of reports on January 25, 2007, March 7, 2007, June 19, 2007, and June 25, 2007. Option 6 pipeline information submitted January 2008. Consultation ongoing. |
| Maine Atlantic Salmon Commission | Consultation/Review on other Maine State Permits | Consultation Request Letter submitted on February 21, 2006. Mitigation Plan to be reviewed coincident with refiling of State permit application anticipated 2014. |

| TABLE 1.3-1<br>**Major Permits, Approvals, and Consultations for the Downeast LNG Project** | | |
|---|---|---|
| **Agency** | **Permits/Approvals/Consultations** | **Anticipated Application Filing/Consultation Date** |
| Office of State Fire Marshal | Blast Permit<br>Permit for aboveground storage and flammable and combustible liquids | Application to be submitted prior to construction. |
| Maine Department of Transportation (Maine DOT) | Site access, driveway, traffic movement permit and Route 1 improvements<br>Utility location permit | Application to be submitted prior to construction. |
| Maine Department of Inland Fisheries and Wildlife (Maine DIFW) | Maine Endangered Species Act | Consultation Request Letter submitted on February 21, 2006. Mitigation Plan to be reviewed coincident with refiling of State permit application anticipated 2014. |
| **LOCAL** | | |
| Town of Robbinston | Conditional Use Permit, Site Plan Approval, and Maine Mandatory Shoreland Zoning Act (delegated to Town via Town Zoning Regulation Adoption) | Conditional Use Permit, Site Plan Approval, and Shoreland Zoning Act approved February 16, 2006. |
| | Plumbing Permit, Flood Hazard Development Permit, Road Improvement | Application to be submitted prior to construction. |
| Town of Baring Plantation | Town Road access for Sendout Pipeline Right-of-Way | To be submitted prior to construction. |
| City of Calais | Town Road access for Sendout Pipeline Right-of-Way | To be submitted prior to construction. |
| | Maine Mandatory Shoreland Zoning Act | Consultation initiated March 2007. To be submitted coincident with refiling of State permit application anticipated 2014. |
| Town of Princeton | Town Road access for Sendout Pipeline Right-of-Way | To be submitted prior to construction. |
| Town of Baileyville | Town Road access for Sendout Pipeline Right-of-Way | To be submitted prior to construction. |

## 1.4 PUBLIC REVIEW AND COMMENT

On January 5, 2006, Downeast filed a request with FERC to implement the Commission's pre-filing process for the Downeast LNG Project. At that time, Downeast was in the preliminary design stage of the project and no formal application had been filed with FERC. The purpose of the pre-filing process is to encourage early involvement of interested stakeholders, facilitate interagency cooperation, and identify and resolve issues before an application is filed with FERC. On January 25, 2006, FERC granted Downeast's request and established a pre-filing Docket No. (PF06-13-000) to place information filed by Downeast and related documents issued by FERC into the public record. All of the information Downeast filed with FERC prior to December 22, 2006 is in Docket No. PF06-13-000. Downeast's application and all project-related information filed on or after December 22, 2006 by Downeast and others are in Docket Nos. CP07-52-000, CP07-53-000, CP07-53-001, CP07-54-000, and CP07-55-000.

On December 20, 2005, Downeast submitted an LOI to the Coast Guard; on January 6, 2006 and February 8, 2006, Downeast submitted amendments to its LOI. The first LOI initiated the Coast Guard's review of the safety and security of the proposed project as part of its preparation of an LOR that would be issued for the project by the local COTP.

On March 13, 2006, the FERC issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Proposed Downeast LNG Project, Request for Comments on Environmental Issues, and Notice of a Joint Public Scoping Meeting* (NOI). The NOI explained that FERC and the Coast Guard would be working together to evaluate the project, with FERC assessing potential environmental impacts and the Coast Guard assessing maritime safety and security issues. The NOI was sent to 801 interested parties, including federal, state, and local officials; agency representatives; tribes; conservation organizations; local libraries and newspapers; and property owners within 0.5 mile of the proposed LNG terminal and along the proposed pipeline route. Issuance of the NOI opened the public comment period and established a closing date of April 17, 2006 for receiving written comments. In total, 75 letters were received in response to the NOI.

On March 28, 2006, the FERC and the Coast Guard conducted a joint public scoping meeting in Robbinston, Maine to provide an opportunity for the public to learn more about the proposed Downeast LNG Project and to provide comments on environmental issues to be addressed in the draft EIS. Eleven people spoke at the meeting and their comments were recorded by a court reporter. A transcript of the scoping meeting has been entered into the public record for the Downeast LNG Project. On March 28, 2006, the FERC also conducted a site visit, open to the public, of Downeast's LNG terminal site and the pipeline route.

On September 18, 2006, the FERC issued a *Supplemental Notice of Intent to Prepare an Environmental Impact Statement for the Proposed Downeast LNG Project and Request for Comments on Environmental Issues*. This NOI described two additional natural gas sendout pipeline routes that had been identified since the NOI dated March 13, 2006. Downeast identified one of these routes as its new preferred route. The NOI provided information about the new preferred and alternative routes and requested comments on the new preferred route to identify issues to address in the EIS. The NOI was sent to 996 interested parties, including federal, state, and local officials; agency representatives; tribes; conservation organizations; local libraries and newspapers; and property owners. The comment period for the NOI closed on October 18, 2006. In total, 47 letters were received in response to the Supplemental NOI.

On December 1, 2006, the FERC issued an additional *Supplemental Notice of Intent to Prepare an Environmental Impact Statement for the Downeast LNG Project and Request for Comments on Environmental Issues Related to the Potential Expansion of the Maritimes & Northeast Pipeline System*. This Supplemental NOI disclosed the nature of the facilities we believed at that time would potentially be required to expand M&NE's system, based on information provided to Downeast by M&NE, and requested comments regarding the possible environmental impact of those facilities. The NOI was sent to 669 interested parties, including federal, state, and local officials; agency representatives; tribes; conservation organizations; local libraries and newspapers; and property owners. In total, 11 letters were received in response to this Supplemental NOI. As described in section 1.0, we have determined that M&NE's system would be capable of transporting the gas proposed by Downeast with changes in gas flow; therefore, potential M&NE facilities are no longer included in this EIS.

On February 13, 2008, the FERC issued a third *Supplemental Notice of Intent to Prepare an Environmental Impact Statement for the Proposed Downeast LNG Project and Request for Comments on Environmental Issues Related to the Modification of the Preferred Pipeline Route.* The Supplemental NOI described the modification of the preferred natural gas sendout pipeline route, to avoid crossing the Moosehorn NWR, as well as four minor route deviations in other locations. The Supplemental NOI provided information about the new pipeline route and requested comments to identify issues to be addressed in the draft EIS. The comment period for this NOI closed on March 13, 2008. The NOI was sent to 1,571 interested parties, including federal, state, and local officials; agency representatives; tribes; conservation organizations; local libraries and newspapers; and property owners. In total, ten letters were received in response to the Supplemental NOI.

In addition to the public notice and scoping process discussed above, the FERC staff conducted agency consultations and participated in interagency meetings to identify issues that should be addressed in this EIS. This included interagency meetings on March 27, 2006 in Augusta, Maine and on September 19, 2006 in Topsham, Maine to discuss the project and the environmental review process with federal and state agencies, and an international commission. These agencies included the Coast Guard, COE, NOAA Fisheries, EPA, National Park Service, FWS, Moosehorn NWR, Bureau of Indian Affairs (BIA), Passamaquoddy Tribal Government, Acadia National Park, Roosevelt Campobello International Park Commission, Maine Department of Conservation, Maine SPO, Maine DEP, Maine State Fire Marshal, Maine Department of Emergency Management, Maine Public Utilities Commission, and Maine Atlantic Salmon Commission (Maine ASC).

Issues identified during scoping covered a broad range of categories. The greatest number of comments received concerned safety, alternatives, purpose, and need. Specifically, these comments addressed the physical design and placement of the terminal and pipeline; methods of construction; the need for another LNG terminal considering that LNG terminals have already been proposed and approved in the nearby provincial region of Canada; and the lack of a regional siting approach to determine the best location for the facility.

Potentially adverse effects to fish and wildlife had the next greatest number of comments; including concerns of impact to high-quality marine and terrestrial wilderness areas such as the Moosehorn NWR and several Canadian nature preserves. Concern for sensitive species was also the subject of comments, specifically the bald eagle, Atlantic salmon, New England cottontail, and several marine mammals. Socioeconomic concerns were the next highest category of public comment, including concerns for the potential adverse effects on tourism, commercial fishing, United States-Canadian economic relations, property values in proximity to the project facilities, and benefits from increased jobs and tax revenues. Various safety issues were also raised, including safeguards against terrorist attacks, accidental explosions (vessel and/or terminal), and available emergency response personnel or equipment for such events.

Other categories of comments, listed in order of number of comments received, included threatened and endangered species; water quality; vessel transit through Canadian waters; wetlands; cumulative effects; noise; visual effects; cultural resources; land use; air quality; vegetation; recreation; and geology and soils. Table 1.4-1 summarizes the major issues raised during the scoping process and the section of this EIS where these concerns are discussed.

TABLE 1.4-1

**Issues Identified and Comments Received During the Public Scoping Process for the Downeast LNG Project**

| Issue | Comment | Section Where Comment/Issue Addressed in EIS: |
|---|---|---|
| General | Procedural issues, LNG vessel transit through Canadian waters, increased industrial activity, applicant/agency attention to local stakeholder input | 1.3, 1.4, 1.5 |
| Purpose and Need | The EIS should include a discussion of how much LNG is needed in New England – now and in the future, and whether or not other proposed projects in the United States or Canada could adequately meet that demand | 1.1, 3.2 |
| Project Description | Siting of project, construction options, design, construction and operation, marine navigation, pipeline routes, increased traffic and crime potential | 2.0, 2.3, 2.6, 2.7, 4.8, 4.9, 4.12 |
| Alternatives | Alternative construction sites and pipeline corridors to reduce environmental impact, alternative energy sources to LNG, alternative regasification and pollution control techniques | 3.2, 3.4, 3.5, 3.6, 3.8 |
| Geology | Seismic instability of the region, presence of Oak Bay Fault, regional subsidence | 4.1.4.1, 4.1.4.3 |
| Soils | Shoreline and submerged lands erosion, ground heaving in winter, sedimentation from dredging and operations | 4.2.1, 4.2.4, 4.2.8 |
| Water Resources | Vernal pools, stream crossings, dredging effects, water uptake for cooling and ballast, private and public well water impacts, surface and groundwater pollution, discharges/sediment plumes into coastal waters, turbidity, water circulation, impacts to marine and aquatic organisms | 4.3.1, 4.3.2, 4.5.2, 4.13.1 |
| Wetlands | Minimizing impacts on wetlands, identification along pipeline routes, preparation of a wetlands assessment, buffer zones to protect wetlands and associated animals | 2.3.2.2, 4.4.1, 4.13.2 |
| Vegetation | Impacts on streamside (riparian) vegetation, deforestation, rare plant species near pipeline routes, herbicide application | 2.3.2.2, 2.6.2, 4.4.2 |
| Fish and Wildlife | Effect on habitat, designated wildlife refuges and managed areas, fish and Essential Fish Habitat, birds, deer, lobster and other shellfish, marine mammals, acoustic effects, effects on all life stages of organisms | 4.5, 4.13.3, 4.13.4, Appendix C |
| Threatened and Endangered Species | Atlantic Salmon, bald eagles and their nesting sites, whales including the right whale, leatherback sea turtles, plant species | 4.6, 4.13.3, Appendix C |
| Land Use | Impact of industry in nonindustrial areas, pier location and use, impact on Moosehorn National Wildlife Refuge and other protected areas, right-of-way on private property | 3.5.1, 4.7.2, 4.7.3, 4.13.8 |
| Recreation | Boating, access to beaches, whale watching, sea-kayaking, fishing, birding, encroachment of ATV use along pipeline corridors | 4.7.3, 4.13.8 |
| Visual Impacts | Views disrupted by the pier and terminal, Maine Rule for Assessing and Mitigating Impacts to Scenic and Aesthetic Uses (Chapter 315 of NRPA), lighting (especially at night), treed buffers, disruption to wildlife, landscaping/mowing | 4.7.4, 4.13.8 |
| Socioeconomics | Property values, impacts on tourism, fisheries and aquaculture industries, insurance costs | 4.8.2, 4.13.7 |
| Cultural Resources | Native American cultural issues, unanticipated discoveries, and potential impacts on Saint Croix Island International Historic Site, the Roosevelt Campobello International Park, and prehistoric fish weir sites | 4.7.3, 4.10, 4.13.6 |
| Air Quality | Emissions from terminal and vessels, health effects of emissions on humans and wildlife, air quality at national parks | 4.11.1, 4.13.5 |
| Noise | Duration of noise and impact on landowners in proximity to facility, noise at night, vessel noise and marine mammals | 4.11.2, 4.13.5 |
| Reliability and Safety | Local emergency response, accident data, terrorism, construction safety, navigation hazards | 2.7, 4.8.5.2, 4.12 |

| TABLE 1.4-1<br>**Issues Identified and Comments Received During the Public Scoping Process for the Downeast LNG Project** | | |
|---|---|---|
| **Issue** | **Comment** | **Section Where Comment/Issue Addressed in EIS:** |
| Cumulative Impacts | Combined impact of Downeast, Quoddy Bay, and other LNG terminals and pipelines | 4.13 |
| M&NE Downstream Expansion | Additional environmental and other impacts from a pipeline expansion; requirement for expansion if Downeast is built | 1.0 |

The draft EIS was issued on May 15, 2009, and mailed to federal, state, and local government agencies; elected officials; Native American tribes; local libraries and newspapers; intervenors to the FERC's proceeding; landowners; and other interested parties. The distribution list was included as Appendix A of the draft EIS. The draft EIS was also submitted to the EPA for issuing its formal public Notice of Availability (NOA) in the FR. The public had 45 days after the date of EPA's notice in the FR to review and comment on the draft EIS, ending on July 6, 2009.

The FERC held one public comment meeting during the draft EIS comment period on June 16, 2009, in Robbinston, Maine. The meeting provided interested parties with an opportunity to present oral comments on the analysis of the environmental impacts of the project as described in the draft EIS. Additionally, a total of 112 letters were sent in response to the draft EIS. All environmental comments on the draft EIS have been addressed in this final EIS. A transcript of the meeting and copies of each comment are part of the public record for this project. The FERC staff's responses to relevant comments on the draft EIS are provided in Appendix S of this final EIS. Substantive changes in the final EIS are indicated by vertical bars that appear in the margins. The changes were made both in response to comments received on the draft EIS and as a result of updated information that became available after the issuance of the draft EIS.

On March 28, 2013, the Commission issued a Supplemental draft EIS for the project, which was mailed to the agencies, individuals, and organizations on the mailing list, and was filed with the EPA for issuance of a formal NOA in the FR. The scope of the Supplemental draft EIS was limited to a revised reliability and safety analysis of the LNG terminal and carrier transit, to address DOT clarifications on its safety standards in 49 CFR 193. The public had 45 days after the EPA's notice in the FR to review and comment on the Supplemental draft EIS, ending on May 20, 2013. A total of 84 letters were sent in response to the Supplemental draft EIS in time for inclusion in the final EIS; these comments have been addressed in this final EIS and are also included in Appendix T as applicable.

This final EIS is being mailed to the agencies, individuals, and organizations on the mailing list in Appendix A, and was filed with the EPA for issuance of a formal public NOA in the FR. In accordance with CEQ regulations implementing NEPA, no agency decision on the proposed action may be made until 30 day after the EPA publishes a Notice of Availability of the final EIS in the Federal Register. However, CEQ regulations provide an exception to this rule when an agency decision is subject to a formal internal appeal process that allows other agencies or the public to make their views known. This is the case at the FERC, where any Commission decision on the proposed action would be subject to a 30-day rehearing period. Therefore, the FERC decision may be made and recorded concurrently with the publication of the final EIS.

## 1.5 CORRESPONDENCE WITH CANADIAN GOVERNMENT

In a letter dated April 7, 2006 from the Canadian Ambassador, and a letter dated May 2, 2006 from the Premier of New Brunswick, the following three concerns were stated in opposition to the proposed Downeast and the previously proposed Quoddy Bay LNG facilities[6] on the Maine side of Passamaquoddy Bay: (1) the navigational challenges of the proposed transit route through Head Harbour Passage, Passamaquoddy Bay, and its approaches; (2) the impact of safety and security zones associated with LNG vessels; and (3) the impact of accidents such as spills from the facilities or vessels. These concerns are cited as negatively impacting the health and safety of the local residents, the economic viability of fishing and tourism in the region, and the pristine environment of the region. In the letter from the Canadian Embassy, the concerns were also the basis for the decision by the Canadian government to conduct its own study of the navigational, safety, environmental, and other impacts of these projects.

In response to these letters, the Commission sent a letter to the Canadian Coast Guard, Canadian Environmental Assessment Agency, Environment Canada, Fisheries and Oceans Canada, Foreign Affairs Canada, and Transport Canada on June 19, 2006, requesting input on: (1) the impact of LNG vessel traffic on other Passamaquoddy Bay Waterway and St. Croix River users, including fishing and recreational boaters near Deer Island, Campobello Island, and Saint Andrews; (2) the potential impacts on Canadian tourism, including whale watching tours and kayaking excursions, and aquaculture facilities; (3) potential noise and visual impacts on Saint Andrews' residents from the LNG terminals; and (4) the potential impact of LNG vessel traffic transiting through Head Harbour Passage and Passamaquoddy Bay into the mouth of the St. Croix River on sensitive species (e.g., whales, turtles, etc.), sensitive ecosystems, and environmentally sensitive areas. This request effectively covered all concerns outlined by the Canadian government to this date.

On October 11, 2006, the Premier of New Brunswick, Shawn Graham, submitted a letter requesting the Province of New Brunswick to be a formal intervener in the U.S. regulatory process. The request was premature since an application had not been filed with the FERC. The letter outlined the same concerns given in the two previous letters as the basis for this decision, but also stated that Downeast should be held financially responsible for all economic and environmental impact studies, all mitigation costs including the cost of increased emergency services, any negative impact on existing fishing and tourism industries, and all necessary compensation to New Brunswick and its people. The motion also declared that "New Brunswick intends to urge the appropriate federal authorities in Canada, including the Canadian Coast Guard, to initiate such proceedings to review the proposed transit in order to determine under what conditions Canadian waters may be suitable for LNG vessel transit. Such review should include the transit up the Western Passage, through the entrance to Passamaquoddy Bay and the St. Croix River because the US-Canadian border traverses through the waters."

[6] In an Order issued October 17, 2008, the FERC dismissed the Quoddy Bay LNG application.

On January 22, 2007, the Province of New Brunswick formally filed a Motion for Leave to Intervene and Comment. On February 14, 2007, the Canadian Ambassador filed a letter stating that the Government of Canada will not permit LNG vessels to pass through Head Harbour Passage. The letter stated that this decision was based on the study announced in the letter dated April 7, 2006. The letter stated that the study found that the impact of the proposed siting of the terminals, and the potential passage of LNG vessels through the environmentally sensitive and navigationally challenging marine and coastal areas of the sovereign Canadian waters of Head Harbour Passage present risks to the region of southwest New Brunswick and its inhabitants that the Government of Canada cannot accept.

The Province of New Brunswick filed a Motion to Suspend Proceedings for both the Downeast and Quoddy Bay LNG Projects on February 26, 2007, stating that because the Government of Canada decided to prohibit LNG vessel traffic from passing through the Head Harbour Passage, the projects were no longer viable. On June 1, 2007, the Commission issued an Order that denied this Motion to Suspend Proceedings. The Commission recognizes that such issues of international law are beyond its purview. However, the Commission does not agree with New Brunswick that the Commission should exercise its discretion to suspend proceedings because issues relating to LNG vessel passage through Canadian waters have not yet been resolved. Therefore, Commission staff has continued its review of the proposed Downeast LNG Project and prepared this EIS.

On March 2, 2007, we responded to the Canadian government and requested a copy of the study prepared by the Canadian government. We also stated that the FERC staff would continue to prepare an EIS for both the Quoddy Bay and Downeast LNG Projects, since neither applicant had withdrawn its respective application (we note that Quoddy Bay LNG's application was dismissed without prejudice by the Commission in October 2008). The letter also requested the appropriate Canadian environmental, coastal, and navigational safety agencies assist the FERC staff and the Coast Guard in our analysis. The Government of Canada provided a copy of *A Study of the Anticipated Impacts from the Development of Liquefied Natural Gas Terminals on Passamaquoddy Bay* (Canadian Study) (SENES 2007) to the Commission in October 2007.

On March 9, 2007, the U.S. Assistant Secretary of State for Legal Affairs sent a letter to Maine Senator Olympia Snowe, stating the "attempts to short-circuit the FERC process are inappropriate" and that "all vessels enjoy a non-suspendable right of innocent passage…through Head Harbour Passage." It also emphasized the "appropriateness and potential value of Canada and the relevant province participating in the FERC process."

In response to the draft EIS, in letters dated July 2, 2009 and December 4, 2012 from the Premier of New Brunswick, and letters dated July 7, 2009, and February 3, 2010 from the Canadian Ambassador, these representatives reiterated the Government of Canada's opposition to the passage of LNG tankers through Head Harbour Passage in New Brunswick. Reasons cited included Canada's historic title to these waters and the right to control and regulate use, and concerns regarding navigation safety and environmental impacts. In a February 26, 2010 response, the Commission stated that it recognizes the Canadian Government's concerns and that issues relating to LNG tanker passage through Canadian waters have not yet been resolved, but noted that it is necessary for the Commission staff to continue processing the application for the project so that the project can be put before the Commission for a decision. The position of the

Canadian government will be considered by the Commission when it makes its decision on the proposal.

In response to the Supplemental draft EIS, in a letter dated May 17, 2013, the Canadian Ambassador reiterated the Government of Canada's opposition to the passage of LNG tankers through Head Harbour Passage in New Brunswick, citing concerns regarding navigation safety and environmental and economic impacts, as well as Canada's historic title to these waters and the right to control and regulate its use. In a June 18, 2013 response, the Commission stated that is has a legal obligation to continue processing the Downcast LNG Project application so that all the issues can be properly documented before it makes a decision on the proposal.

In addition to these letters, there has been other correspondence from Downeast, Quoddy Bay, and Maine SPO in response to the motions to suspend proceedings and the rights of passage for LNG vessels through Head Harbour Passage.

This EIS addresses environmental, navigation, safety, and security concerns that have been identified during the EIS scoping process, including issues and concerns raised in the Canadian Study (SENES 2007). It addresses the resources that would be affected by the project and analyzes the project's impacts and compliance with U.S. laws and regulations. It also addresses resources on the Canadian side to the extent that they would be affected by the project based on information provided by Downeast, our own research, and information provided in the Canadian Study (SENES 2007). We have evaluated and provided protective mitigation measures for species and resources that may be present along the waterway based on U.S. laws and regulations discussed in section 1.3. However, we have not specifically addressed measures that may be required by Canadian regulations. The Coast Guard's WSR recommends that Downeast develop standard operating parameters to be approved by the Coast Guard and coordinated with the Government of Canada, as well as a Transit Management Plan that outlines the roles and responsibilities of federal, state/provincial, and local stakeholders. The WSR also recommends that Downeast follow the Canadian maritime laws and regulations that comply with customary international law, including the right of non-suspendable innocent passage through an international strait.

The following Canadian environmental laws and regulations may apply to aspects of this project. Many of them are similar to our laws and regulations discussed in section 1.3.

*Federal Species at Risk Act (SARA)*

The purposes of SARA are to prevent Canadian indigenous species, subspecies, and distinct populations from becoming extirpated or extinct, to provide for the recovery of endangered or threatened species, and to encourage the management of other species to prevent them from becoming at risk. SARA prohibits killing, harming, harassing, capturing, or taking listed species, and destroying their associated habitats. Regulatory agencies overseeing jurisdictional enforcement of SARA include Environment Canada, Parks Canada, and Fisheries and Oceans Canada. Currently, there are over 400 species afforded protection under this act.

*Fisheries Act*

The Fisheries Act provides the legislative authority for the management and regulation of fisheries (salt and fresh water), including access, control over the conditions of harvesting, and enforcement regulations. In addition to allocating the right to fish, protecting fish and fish habitat is a major focus of the act. The requirements of the Fisheries Act apply to all lands: public, private, and aboriginal. Fisheries and Oceans Canada is the primary agency responsible for enforcement of the regulations associated with the act, though Environment Canada enforces regulations associated with portions of the act under the Pollution Prevention Provisions, Section 36(3).

*Canadian Environmental Protection Act (CEPA)*

The purpose of CEPA is to prevent pollution and protect the environment and human health. Legislation under CEPA establishes permitting processes and regulations for the production, transport, and release of listed toxic substances, emissions from vehicles, engines, and equipment, and the disposal of substances at sea. The law also provides for the gathering of information for research, creating inventories of data, risk assessment, and developing objectives, guidelines, and codes of practice. Permitting and regulatory enforcement under CEPA is administered by Environment Canada.

*Canada Water Act*

The Canada Water Act enables the federal and provincial governments to make joint arrangements for water resources and water quality management in Canadian waters, and regulates discharge into water resources. The Canada Water Act is administered by Environment Canada.

*Navigable Waters Act*

The Navigable Waters Act is designed to protect the public right of navigation in Canadian waters by prohibiting the building, placing, or maintaining of any work whatsoever in, on, over, under, through, or across any such navigable water, without the authorization of the Minister of Fisheries and Oceans Canada.

*Migratory Birds Convention Act (MBCA)*

Under the MBCA, the Canadian government has the authority to pass and enforce regulations to protect migratory bird species, which are included in the Migratory Birds Convention of 1916 between Canada and the United States. In Canada, the MBCA is administered by the Wildlife Enforcement Division of Environment Canada. Enforcement of the act and regulations is the responsibility of the Canadian Wildlife Service, the Royal Canadian Mounted Police, and provincial or territorial law enforcement authorities.

*New Brunswick Endangered Species Act*

The New Brunswick Endangered Species Act (Chapter E-9.101) protects two categories of species: endangered and regionally endangered. The act prohibits possessing, harming, harassing, disturbing, and/or killing individual members of listed species and destroying critical habitat for these species.

## 1.6 NONJURISDICTIONAL FACILITIES

Under Sections 3 and 7 of the NGA, the FERC considers all relevant factors bearing on the public convenience and necessity as part of a decision to approve jurisdictional facilities. The jurisdictional facilities for the Downeast LNG Project include the proposed LNG terminal facilities and proposed new natural gas pipeline and its associated aboveground facilities. Occasionally, proposed projects have associated facilities that do not come under the jurisdiction of the Commission.

There is one nonjurisdictional facility related to this project, a new electric transmission line with a new electric substation. These are discussed in section 2.9 of this EIS.

## 2.0 DESCRIPTION OF THE PROPOSED ACTION

The FERC is the federal agency responsible for authorizing applications to construct and operate onshore LNG import and interstate natural gas transmission facilities. The Coast Guard is the federal agency responsible for assessing the suitability of the waterway for LNG marine traffic. The Coast Guard is also the federal agency responsible for issuing an LOR regarding the suitability of the waterway for LNG marine traffic.

The proposed action before the FERC is to consider issuing to Downeast a Section 3 authorization for an LNG import facility and a Section 7 Certificate of Public Convenience and Necessity for a new natural gas pipeline. As indicated in the Coast Guard's LOR to Downeast, the Passamaquoddy Bay Waterway was determined to be suitable for the type and frequency of marine traffic associated with the proposed project, provided that all of the risk mitigation measures outlined in its WSR were fully implemented by Downeast. These measures have been listed in section 1.3 of the WSR. Specific details of these measures, where applicable, and the resources needed to implement them, are described in the Coast Guard's WSR, included as Appendix B.

### 2.1 PROPOSED FACILITIES

Downeast proposes to construct and operate a new LNG import, storage, and vaporization terminal on the south side of Mill Cove, in Robbinston, Maine slightly south of the confluence of Passamaquoddy Bay and the St. Croix River between the towns of Eastport, Perry, and Calais, Maine. In addition, Downeast proposes to construct and operate a new 29.8-mile-long, 30-inch-diameter natural gas sendout pipeline extending from the LNG terminal to the existing M&NE pipeline system at the Baileyville Compressor Station. General LNG terminal and pipeline location maps are shown on figures 1-1 and 2.1-1. The proposed LNG terminal plot plan is shown on figure 2.1-2. Detailed pipeline route maps are included in Appendix E (see figures E-1 to E-6).

#### 2.1.1 LNG Terminal Facilities

The LNG terminal facilities would consist of a vessel unloading facility (one vessel berth and unloading platform), two LNG storage tanks, vaporization and vapor handling system, vent system, hazard detection and response system, hazard control system, metering, and support buildings and piping structures.

Downeast's LNG terminal would receive LNG from up to 60 LNG vessels per year, or once every five days in the winter and once every eight to ten days in the summer. Upon entering the Gulf of Maine, the vessels could potentially take two routes to reach the routine pilot boarding area near East Quoddy Head. One route is east of Grand Manan Island and follows the Vessel Traffic Scheme (VTS) as shown on nautical charts. The second route follows the Grand Manan Channel, west of Grand Manan Island. The Coast Guard's WSR does not specifically authorize or approve one of the proposed routes to the entrance of Head Harbour Passage. The route chosen by the LNG vessel captain would depend on visibility, wind, tide cycle, and other such constraints. While no mandatory deep draft vessel routing is currently prescribed for the proposed transit area, Downeast proposes that LNG vessels en route to the proposed terminal enter the area via the Grand Manan Channel only. However, we have assessed the environmental impacts for both approaches to Head Harbour Passage.

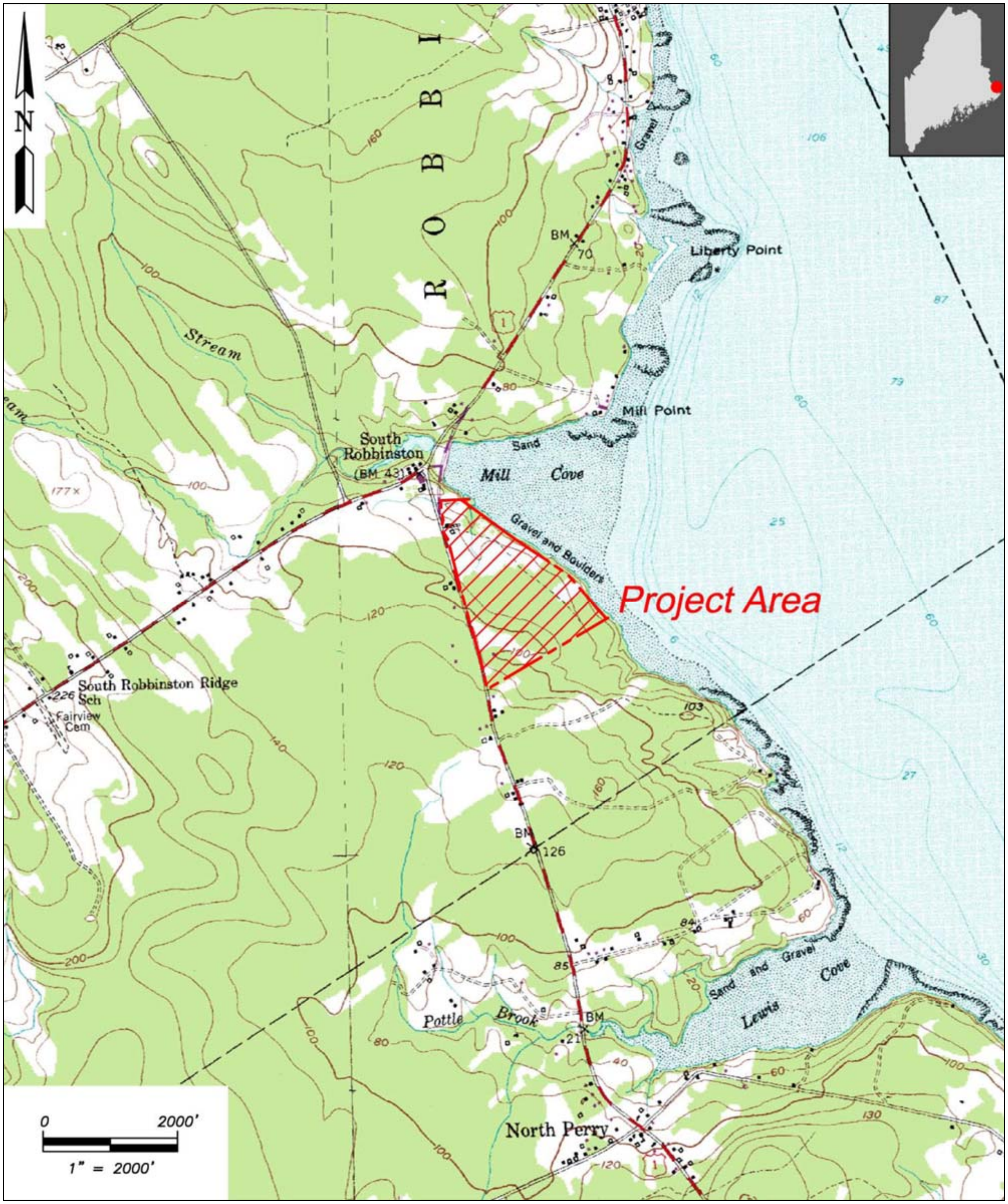



**Figure 2.1-1**
**Downeast LNG Project**
**LNG Terminal Location Map**

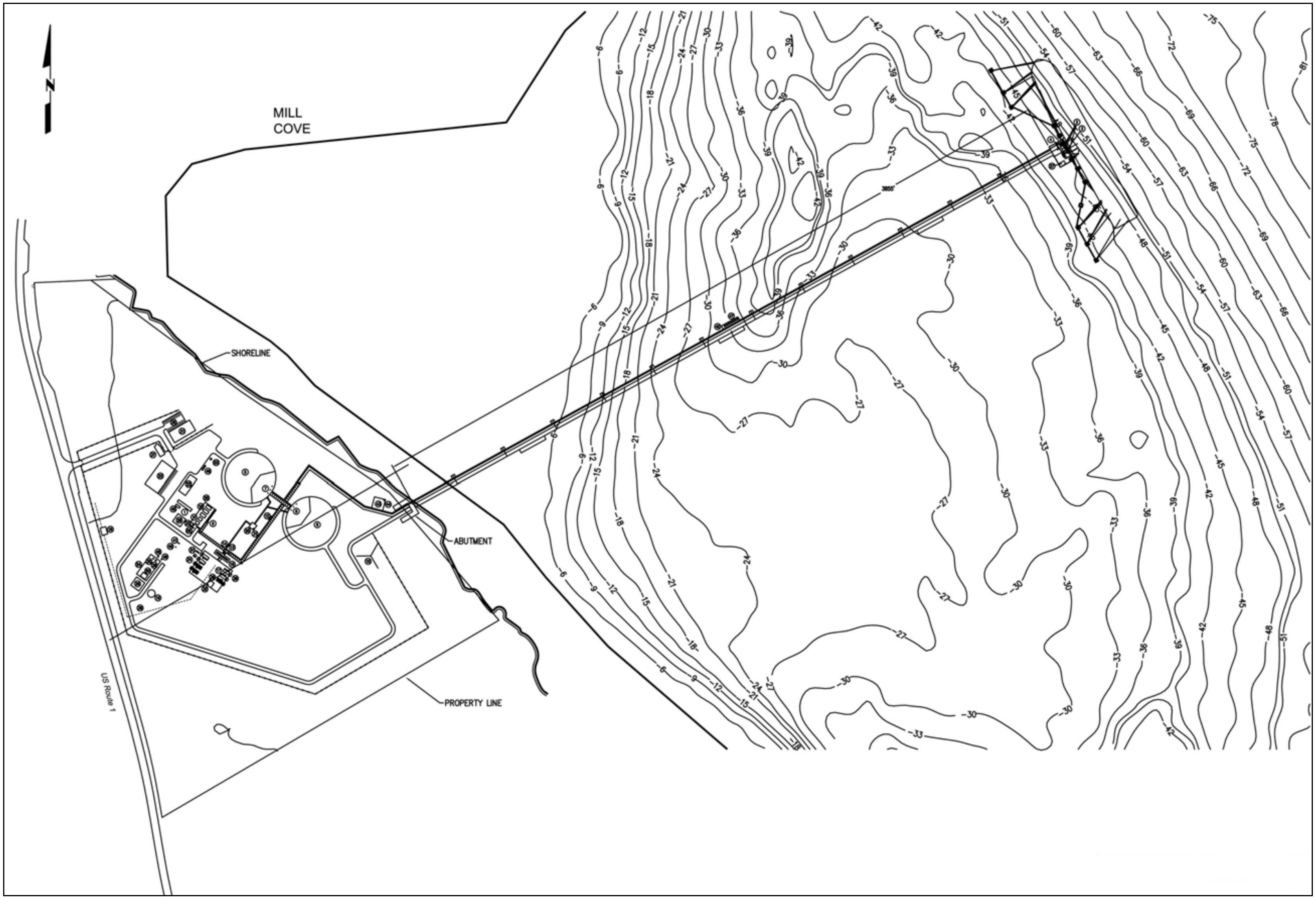



**Figure 2.1-2**
**Downeast LNG Project**
**LNG Terminal Plot Plan**

Upon entering Head Harbour Passage, the LNG vessel would pass Campobello Island along the island's north shore, to the northerly confluence of Friar Roads south of Indian Island and Cherry Isle, into U.S. waters as it nears Eastport, Maine. It would pass along that city's eastern shore, up Western Passage, passing Quoddy, Maine to the west and Deer Island, New Brunswick to the east. The vessel's transit would continue north through Western Passage along the international boundary between Canada and the United States, keeping Deer Island to the right and the Maine coast on the left until turning northwesterly back into U.S. waters opposite Lewis Cove to reach the proposed project site near the mouth of the St. Croix River. A typical transit, from the time an LNG vessel would enter Head Harbour Passage to the time it reaches the proposed Downeast LNG terminal, would take approximately two and one-half to three and one-half hours. Figures showing the waterway for LNG marine traffic are provided in Appendix F.

Downeast's application to FERC proposed using vessels ranging in size from 70,000 to 165,000 $m^3$, with the potential for future vessels ranging up to 220,000 $m^3$. However, Downeast only conducted vessel simulations to investigate the feasibility of navigating LNG vessels up to 165,000 $m^3$ cargo capacity from the pilot boarding area off East Quoddy Head to the proposed LNG terminal. Based on the vessel simulations, Downeast has proposed using LNG vessels with cargo capacities no greater than 165,000 $m^3$.

The 2004 Sandia National Laboratories (Sandia) Report (see section 4.12) that assessed safety implications of a large LNG spill over water only evaluated LNG vessels with an average cargo carrying capacity of 148,000 $m^3$. The Coast Guard's WSR (Appendix B) was based on the analysis in the December 2004 Sandia Report. However, the WSR states that, "based on the conclusions presented in the Sandia Report of May 2008, the sizes of the hazard zones applied in association with the Downeast LNG site are considered applicable to vessels up to a maximum of 265,000 $m^3$ carrying capacity." Therefore, from an LNG spill risk-consequence perspective, the waterway may be suitable for these larger class vessels. However, should Downeast choose to use vessels with cargo capacity up to 220,000 $m^3$ (the design capacity of the terminal), additional vessel simulations incorporating these larger-sized vessels would need to be conducted to evaluate the navigational aspects of operating vessels of this size along the waterway and during docking and undocking evolutions at the Mill Cove terminal site.

In our draft EIS, the sections on each resource area contained a discussion of the potential impact of an LNG spill, ignited or unignited, occurring along the waterway for LNG marine traffic to assist the Coast Guard in fulfilling its NEPA obligations related to the issuance of the LOR. Since the issuance of the Downeast draft EIS, the Coast Guard has determined that the LOR is not a federal action and that the agency has no NEPA obligations that need to be addressed by the FERC EIS. As a result, we have removed the discussion in section 4 on environmental resources that may be present in the Coast Guard's Zones of Concern. However, the EIS continues to contain a discussion of impacts expected from the transit of the LNG carriers (i.e. shore erosion, ship traffic, ballast/cooling water intake). The discussion regarding the Zones of Concern considered by the Coast Guard in its determination on the type and frequency of LNG marine traffic associated with this proposed project is described in section 4.12.7.

The 19.5-mile route from the pilot boarding area, 1.75 miles due east of East Quoddy Head, to the proposed terminal site is through a deep and broad natural channel. Prior to arrival at the marine terminal, the water depths encountered along the transit route range from about 98 feet off Mill Cove to 165 to 246 feet at the pilot boarding area. The narrowest points along the transit route are approximately 2,000 feet wide – occurring between Dog Island and Deer Island Point, and when passing between buoy R "UH2" and Campobello Island in Head Harbour Passage. The charted depth of water at the proposed marine berth is approximately 45 to 50 feet at mean low water, eliminating the need for maintenance dredging. The approximate distance from the proposed marine berth at the trestle end to the channel centerline is 3,000 feet, providing adequate maneuvering area off the berth for vessel mooring and turning evolutions.

A 3,862-foot-long, 37-foot-wide pier equipped with mooring and ancillary systems would be constructed for the mooring of LNG vessels. The pier would include the following support structures:

- an abutment positioned near the existing bluff line to support the end of the trestle;
- a roadway and pipeway access trestle;
- an unloading platform;
- four breasting dolphins;
- six mooring dolphins;
- interconnecting walkways connecting the dolphins and platform; and
- a support structure for a seawater firewater pump house located midway along the trestle.

The trestle from the terminal shoreline to the unloading platform would consist of a single lane roadway capable of supporting water truck loading and an adjacent pipeway to support the necessary LNG and utility piping and cabling. There would be three vehicle passing areas along the roadway. The trestle and unloading platform would be supported on steel pipe piles that would be vibrated and driven through surficial soils to bedrock and provided with drilled and grouted rock sockets. A concrete deck would be the deck surface for the roadway, unloading platform, and under the pipeway for spill containment.

Breasting and mooring dolphins constructed at the LNG vessel berth would each be supported by single, large diameter steel pipe mono-piles driven to bedrock and inserted into full diameter drilled and grouted rock sockets. The breasting dolphins would be equipped with:

- fenders suitable to safely berth and moor the 70,000 $m^3$ to 165,000 $m^3$ range of LNG vessels being considered with the potential for future vessels ranging up to 220,000 $m^3$; and
- double, high load capacity, quick release mooring hooks.

#### 2.1.1.1 LNG Vessel Deliveries

LNG is currently shipped from a variety of sources around the world, including such locations as Algeria, Australia, Brunei, Indonesia, Malaysia, Nigeria, Oman, Qatar, Trinidad, and United Arab Emirates. Downeast anticipates that LNG could be delivered to the proposed LNG terminal from any of these worldwide sources. Although LNG vessels and their operation are directly related to the use of the proposed LNG terminal, they are not subject to the Section 3 authorization sought in the FERC application. The Coast Guard is the federal agency that exercises regulatory authority over LNG facilities and the associated LNG vessel traffic, which ultimately affects the safety and security of port areas and navigable waterways. In addition to its role as a cooperating agency to FERC, the Coast Guard assesses the suitability of the waterway, and issues an LOR under its regulations. The LOR and associated LOR Analysis (WSR) is provided to FERC and to the applicable state and local authorities having jurisdiction, to assist with their decision-making process concerning the approval of the LNG facility. On January 6, 2009, the Coast Guard COTP issued an LOR and associated WSR that determined that the Passamaquoddy Bay waterway was suitable for the type and frequency of LNG vessels proposed for the Downeast LNG Project provided that all of the recommended risk mitigation measures as outlined in section 4.6 of the WSR were fully implemented by Downeast.

The LNG terminal berth and offloading facility would be designed to handle LNG vessels ranging in cargo carrying capacity from about 70,000 $m^3$ to 165,000 $m^3$ with the potential for vessels with cargo capacity of 220,000 $m^3$. Downeast estimates that its proposed LNG terminal would serve an average of about 60 LNG vessels per year.

Vessels that transport LNG are specially designed and constructed. LNG vessel construction is highly regulated and consists of a combination of conventional vessel design and equipment, with specialized materials and systems designed to safely contain liquids stored at temperatures of -260 degrees Fahrenheit (°F) (-162 degrees Celsius [°C]). The following section presents a brief overview of the main design and safety features of a typical LNG vessel. Figures 2.1-3a and 2.1-3b show a typical LNG vessel.

**Profile**

Many LNG vessels, especially those of the spherical tank design, have a distinctive appearance; their hull shape and dome-style profile are quite different from other types of tank vessels and have a relatively high freeboard (i.e., the portion of the vessel above the water line) in comparison to other vessels. LNG weighs only about 46 percent of the weight of water and is a relatively light cargo; because of its low specific gravity, tank shape and volume usually extend above the main deck to provide increased capacity. On the other hand, some of the more recently built low-elevation membrane type vessels closely resemble conventional vessels in outward appearance, and consequently with their lower freeboards can now pass under most highway and rail bridges, making more ports accessible.

**Hull Design**

All LNG vessels are constructed of double hull-design. Double-hull construction increases the structural integrity of the hull system and provides protection to the primary containment of the cargo if collision, grounding, or other emergency event were to occur. Portions of the space between the inner and outer hulls are used for ballast water, which effectively decreases the vessel's freeboard and increases its overall stability during the non-laden, return voyage to the loading port.

The International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code ) and Coast Guard regulations require that LNG vessels meet a Type IIG standard of subdivision, damage stability, and cargo tank location. The Type IIG criteria ensure the LNG vessel could withstand flooding of any two adjacent compartments without any adverse effect upon the stability of the vessel. The Type IIG design also requires that the cargo tanks be a minimum of 30 inches from the outer hull and a minimum distance above the bottom of the vessel equal to the beam (width) of the vessel divided by 15, or 6.5 feet, whichever is less. This distance factor is intended to prevent or mitigate damage occurring to the cargo tanks in the event of a low energy-type impact. Recent design membrane tanks are surrounded on all sides by heavily strengthened double-hull construction. The distance between the cargo tank and the vessel's hull is at least 7 feet and up to 13 feet in places, including the bottom of the vessel.

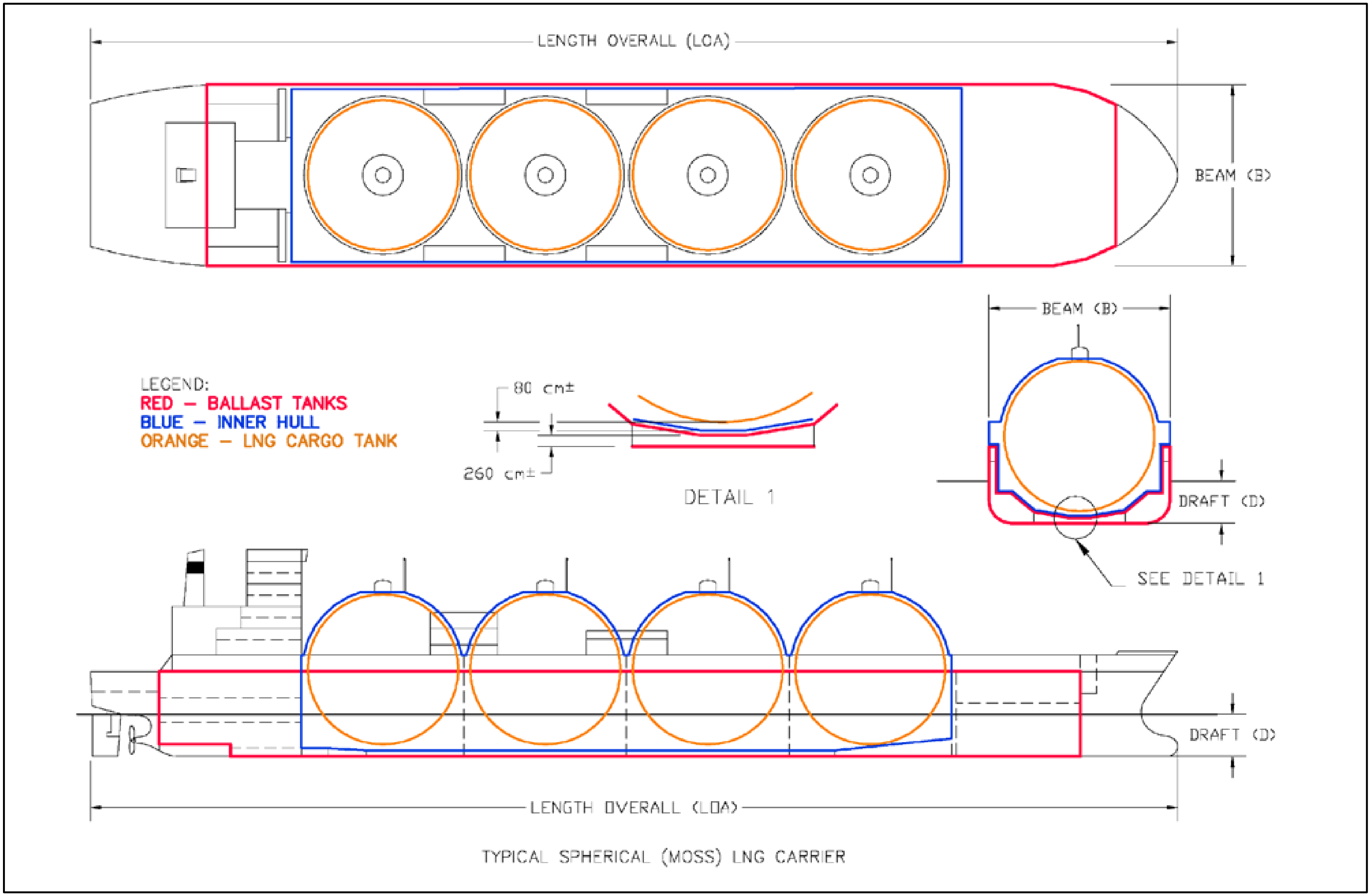
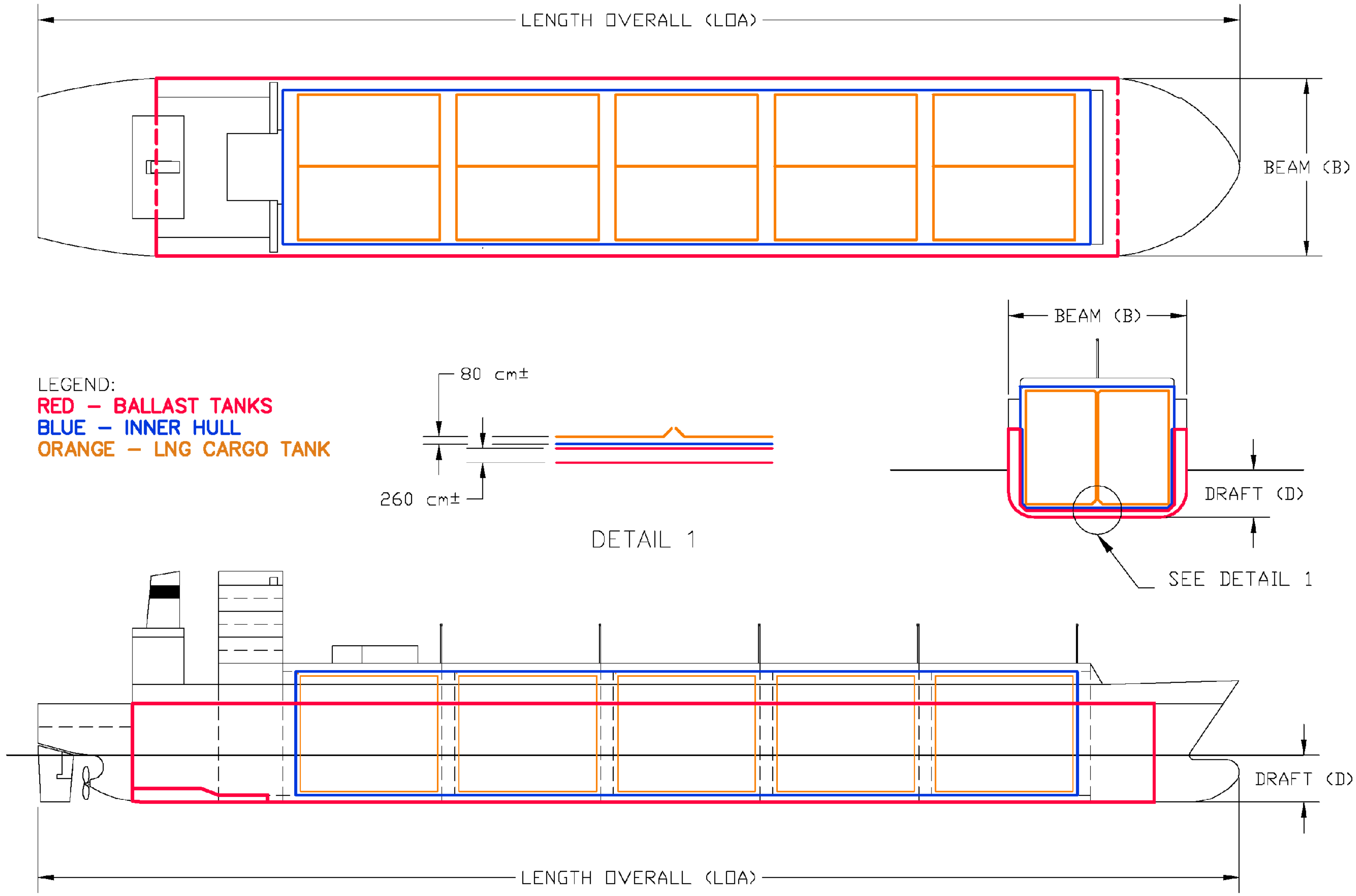



**Figure 2.1-3a**
**Downeast LNG Project**
**Typical Spherical LNG Vessel**




TYPICAL MEMBRANE LNG CARRIER

**Figure 2.1-3b**
**Downeast LNG Project**
**Typical Membrane LNG Vessel**

## Containment Systems

LNG vessels are classified by their cargo containment design. Components of a containment system include the cargo tank (sometimes called a primary barrier), a secondary barrier (depending on tank design), and associated insulation systems (used to inhibit boil off of the gas and protect the steel tank surfaces from direct exposure to cryogenic temperatures). The containment system also includes an extensive array of onboard cargo monitoring and control features for safely receiving, transporting, and discharging the product.

Three basic cargo containment designs have been developed for the marine transportation of LNG. The first type of design, the membrane tank, is supported by the hold/space it occupies. The other two designs, spherical and prismatic, are self-supporting. While membrane tanks could be considered "integral tanks," meaning that they utilize the vessel's structure as the strength member to contain the cargo, a spherical tank could be considered an independent tank and capable of self-support of the cargo's weight.

In the simplest of forms, membrane tanks are composed of a layer of metal (primary barrier), a layer of insulation, another liquid-proof layer, and another layer of insulation. In actuality though, a membrane design is fairly complex and involves the sandwiching of multiple variations of insulation and barrier materials to include different alloys of nickel and steel, perlite, balsa wood, Invar, polyurethane, and aluminum, just to name a few. These built-up layers, or panels, are anchored to the walls of the externally-framed cargo hold, and the mating panel joints sealed. Within the membrane systems, different construction and material variations exist. Membranes are found in industry under the trade names GT or No. 96, Mark III, and CS1. There are three types or formulations of membrane systems—Gaz Transport, Technigaz, and a self-supporting prismatic membrane design termed IHI. Gaz Transport and Technigaz, now a joint enterprise called GTT, developed the CS1 system, which incorporated features of existing Gaz Transport No. 96 and Technigaz MK III membrane systems. GTT membrane designs are increasingly being specified for new vessel construction because the design can be prefabricated and readily tailored to a variety of sizes. The advantages of membrane systems include: material fatigue problems are limited, more cargo carrying capacity, low center of gravity (less roll period), more deck space, and the tanks are more easily inspected internally. The disadvantages are: more complex structural details, higher weight and cost of initial tank construction, not conducive for carrying of partial loads (below 80 percent capacity) due to "free-surface effect," containment space directly around the cargo tanks must be maintained in an inert state, and an accurate stress analysis is harder to ascertain because of the many strength members employed with this type of construction.

The alternative to a membrane tank is a self-supporting tank. The most well-known is the Kvaerner-Moss spherical tank, which as previously mentioned, is the vessel profile that many people equate with the appearance of an LNG vessel in that almost half of the large spherical tanks appear to protrude above a vessel's deck. The early sphere designs were shells of 9 percent nickel steel; subsequently aluminum has been used. This free-standing tank is insulated with multi-layer, close-cell polyurethane panels. The sphere is installed in its own hold of a double-hulled vessel. The sphere is supported around its equator by a steel cylinder or ring, termed the "skirt," which is connected to the vessel's hull. The advantages of the Moss spherical design include: convenient shape for stress analysis, good internal tank and insulation space inspection capability, increased safety in the event of a collision or grounding due to tank location, no secondary barrier is required, tanks are heavier construction, and is a better design for transporting partial loads. The disadvantages are: tanks penetrating the main deck provide less protection, there is less cargo capacity, with 40 percent of the cargo being above the main deck, the vessel's center of gravity is higher (longer periods of roll), and the view from the bridge/pilot house may be more restrictive.

The second type of self-supporting tank is the prismatic IHI by Ishikawajima Heavy Industries of Japan. These tanks are constructed with the framing members, or stiffeners, being internal to the tank. IHI tanks, which are usually constructed of aluminum alloy, 9 percent nickel alloy, or 304 stainless steel, are installed into the hold of a double-hulled vessel and insulated with reinforced polyurethane foam on the bottom and the sides, with covered fiberglass on the top.

LNG vessels are of the double-hulled design regardless of the containment system used. A double bottom and double sides follow the full length of the cargo area and serve as ballast tanks, completely independent of the cryogenic cargo tanks. This double-hulled design provides greatly increased reliability of cargo containment in the event of grounding or collision.

**Pressure/Temperature Control**

LNG is carried as a liquid in order to maximize capacity of the available volume in the cargo tanks. Since it is impractical to force natural gas into a liquid state using pressure, the gas is cooled to about -261°F at the loading facility and then pumped into the vessel's cargo tanks. Because the cargo is so cold, all equipment and associated surfaces are designed and constructed to operate at these extremely cold (cryogenic) temperatures. The intended purpose of all LNG containment systems is to maintain the LNG cargo at its atmospheric boiling point, which is about -260°F [-162°C]. When the liquid is loaded onto a vessel, it immediately starts to "boil," or return to a vapor state as it warms up after contact with relatively warmer surfaces of the containment system and from heat leakage through the insulated surfaces of the tank. The vapor generated is known as boil-off. The amount of boil-off from pre-refrigerated LNG cargo is directly related to the efficiency of the tank insulation. Boil-off, which is primarily methane vapors at ambient temperature, is used as fuel for the vessel's main propulsion system during sea passages. Currently, the majority of LNG vessels burn the boil-off as fuel. Typical boil-off rates range from 0.10 to 0.15 percent of the cargo volume per day, which equates to about 3 percent of the total cargo being "boiled off" and used for fuel during a typical trans-Atlantic crossing. The predominant propulsion systems used on LNG vessels has conventionally been steam-turbine reduction with dual-fuel capability, heavy fuel oil (HFO), and boil off. However, the latest trends in new construction have been towards diesel, diesel-electric, and gas turbine. The IGC Code requires pressure control for the cargo system in order to keep the cargo tank pressure below the tank design pressure or the maximum allowable relief valve setting. The Coast Guard does not permit routine venting of BOG to the atmosphere, thus they require LNG cargo systems used in the U.S. waters be capable of maintaining the cargo for at least 21 days without exterior venting, intended to eliminate the need to vent flammable vapors while in U.S. ports. Thus, all LNG vessels that trade in the United States are fitted with the capability of using the boil-off vapor as fuel for shipboard use or for a waste heat system. As a result, LNG vessels have a tendency towards lower emissions in comparison to conventional oil-fired vessels.

## Ballast Tanks

Sufficient ballast water capacity must be provided to permit the vessel to return to the loading port in a stable condition under all sea conditions (see sections 4.3 and 4.5.2 for additional information on ballast water). Ballast water tanks are arranged within the LNG vessel's double hull and are distinct and completely separate from the vessel's cargo tanks and associated piping.

A ballast control system, which permits the simultaneous ballasting during cargo transfer operations, is also incorporated into each LNG vessel. This allows the LNG vessel to maintain a constant draft during all phases of its operation to enhance performance. Under normal operating conditions, ballast water would be taken onto the vessel while at berth during and after LNG offloading to maintain the trim and stability of the vessel. LNG vessels would require between 14 million (small capacity 125,000 $m^3$ vessel) and 17 million gallons (large capacity 165,000 $m^3$ vessel, including 165,000 $m^3$ diesel vessel) of seawater ballast. This ballast water would be withdrawn from the surrounding area for a duration of approximately 12 hours per 21-hour cargo unloading period.

LNG vessels returning to load the same product usually retain a small quantity of the cargo on board after discharge, termed "heel," to maintain the tanks at the reduced temperature during the ballast voyage. The actual amount of heel would depend on the type of cargo containment, vessel's mode of propulsion, value of product versus bunkers, and anticipated duration of the voyage. On LNG vessels with tanks of the membrane design, it is necessary only to maintain sufficient cargo to ensure that upon arrival there would be some liquid in the bottom of the tanks. On vessels with spherical tanks, a slightly larger quantity of heel is necessary in order to circulate cargo through spray nozzles fitted near the top of the dome in order that sufficient cool down of the tank surfaces are achieved.

## Vessel Safety Systems

The LNG vessels proposed for use in the Downeast Project would have to comply with all federal and international standards, established by many different entities generally categorized as the International Maritime Organization (IMO), the respective flag state, port state, and classification societies regarding LNG shipping. As such, vessels that transport LNG to the Downeast LNG terminal would be fitted with an extensive array of sophisticated cargo monitoring and control systems. These systems would automatically monitor key cargo parameters while the vessel is at sea and during all phases of cargo operations at the marine terminal.

The IGC Code is one of the most important international conventions for LNG vessels and provides a comprehensive number of design and capability requirements that flag states and classification societies then supplement with even more detailed requirements. Requirements under the IGC Code include provisions for hull design and structural analysis criteria, cargo containment design, specific segregation for cargo areas and piping, leak detection and alarms for hold spaces and insulation, pressure monitoring and control, temperature monitoring of the cargo tanks, emergency shutdown of cargo pumps and closing of critical valves, monitoring of tank cargo levels, and gas and fire detection.

The LNG vessels would be fitted with sophisticated navigational and communication equipment including:

- two separate marine radar systems, including automatic radar plotting and radio direction finders;
- LORAN-C receivers;
- echo depth finders; and
- global positioning and communications technology and satellite navigation system.

All LNG vessels also have redundant, independent steering control systems that are operable from the bridge or steering gear room to maintain rudder movement in case of a steering system failure.

**Fire Protection**

All LNG vessels arriving at the Downeast LNG terminal would be constructed according to structural fire protection standards contained in the International Convention for the Safety of Life at Sea (SOLAS).

The vessels would also be fitted with active fire protection systems that meet or exceed design parameters in Coast Guard regulations and international standards, such as the IGC Code and SOLAS, including:

- a water spray (deluge) system that covers the accommodation house and central room, and all main cargo control valves;
- a traditional firewater system that provides water to fire monitors on deck and to fire stations found throughout the vessel;
- a dry powder extinguishing system for LNG fires; and
- a carbon dioxide system for protecting the machinery, ballast pump room, emergency generators, cargo compressors, etc.

**Crew Qualifications and Training**

All officers and crews of the LNG vessels would comply with the International Convention Standards of Training, Certification and Watch Keeping for Seafarers (STCW). Key members of the crew must have specific training in the handling of LNG and the use of the safety equipment. Every transfer of LNG and each cool-down, warm-up, and gas-free operation must be supervised by a qualified person in charge (PIC) as per 46 CFR 154.1831 and the international requirements of Regulation V/1 of STCW. Officers must receive simulator training in the handling of the vessel and the cargo systems specific to the conditions at the project site. The WSR recommends that all pilots receive follow-on full mission bridge simulator training taking into account the intended size and maneuvering characteristics for those LNG vessels under consideration and to ascertain the performance capabilities of intended assist tugs and escort vessels. The Coast Guard's WSR also recommends that Downeast collaborate with all appropriate jurisdictions on joint, complimentary rulemaking to formalize traffic management practices, the implementation of appropriate operating parameters, and among other measures, the need for mandatory pilotage for all deep-draft vessels throughout the transit of the Passamaquoddy Bay Waterway, its approaches, and the St. Croix River.

## Vessel Selection

The specific identity of LNG vessels that would offload at the Downeast LNG terminal would depend on the commercial terms of the LNG purchase agreements. Transportation could be provided by either the LNG buyer or supplier. The different contractual arrangements for LNG transport can result in vessels of different sizes and countries of origin being used to transport LNG to the LNG terminal.

Table 2.1.1.1-1 shows the relative dimensions of LNG vessels that Downeast stated could be used to transport LNG to the Downeast LNG terminal.

TABLE 2.1.1.1-1

**Typical LNG Vessel Characteristics**

| Specifications | Existing Vessels | | | Future Vessels |
|---|---|---|---|---|
| Capacity ($m^3$) | 70,000 | 145,000 | 165,000 | 220,000 |
| Length Overall (feet) | 852 | 950 | 1,030 | 1,033 |
| Beam (feet) | 125 | 162 | 173 | 180 |
| Draft (feet) | 34 | 41 | 43 | 43 |

LNG vessels arriving at the Downeast LNG terminal must comply with all applicable international conventions, appropriate flag state requirements, class society rules and regulations, and Coast Guard port state control measures. They each have specific areas of responsibility which, in some cases, overlap. Overall compliance is demonstrated through periodic inspections and surveys, as attested by the pertinent certificates maintained aboard the vessel. During these examinations and/or inspections, it is also confirmed that the vessel is manned in accordance with international and national requirements and that the vessel's crew is proficient by proper training and certification, as required. Flag states are those states/countries with whom the vessels are registered. Flag states are responsible for ensuring that vessels are constructed in accordance with the applicable international standards and any unique national requirements. Port states are those states to which a vessel trades in commerce. Port states impose laws and regulations specific to their individual ports and areas of jurisdictions. For LNG vessels intending to serve the Downeast LNG facility:

- U.S. Flag LNG Vessel – The Coast Guard Certificate of Inspection (COI) must be valid and endorsed for the vessel to transport LNG (46 CFR 154, 1979). A Coast Guard COI is issued for a period of five years and retention of the COI depends upon the continued maintenance of the vessel in a safe operating condition and satisfactory completion of required annual inspections during the five-year COI period.
- Foreign Flag LNG Vessel – The vessel must have a valid Certificate of Compliance (COC) issued by the Coast Guard. The certificate is issued after the vessel has proven that it complies with the Coast Guard regulations and after it has been satisfactorily inspected by a Coast Guard Marine Safety Office (46 CFR 154, 1979). A COC is valid for a two-year period and remains valid pending satisfactory completion of an annual mid-period examination between COC renewals.

Both United States and foreign flag vessels must be inspected annually by the Coast Guard and the respective flag state. Coast Guard boarding officers from COTP Sector Northern New England would board all LNG vessels in waters subject to the jurisdiction of the United States prior to the vessels arriving in port to ensure applicable safety and security standards are met.

#### 2.1.1.2 LNG Unloading and Transfer Lines

LNG vessels would use onboard pumps to transfer LNG from their cargo tanks to the shore-side storage tanks. Four 16-inch-diameter articulated unloading arms would be installed on the unloading platform to support cargo unloading operations. Three of these arms are designed for LNG offload from the vessel to shore, and one for vapor return, shore to vessel. One of the three LNG delivery arms could also be used for vapor return from the LNG storage tank to the LNG vessel during vessel unloading.

The arms would be fitted with two isolating valves and powered emergency release couplings to protect the arm and the vessel, and to minimize spillage of its liquid content during an emergency disconnect. The arms could handle the range of LNG vessels being considered.

The unloading arms would be connected by manifold to a single 36-inch-diameter, single-walled stainless steel insulated LNG transfer pipeline equipped with thermal expansion loops to transfer the LNG from the unloading platform.

Downeast would design these facilities in accordance with the requirements of 49 CFR Part 193, 33 CFR Part 127, and National Fire Protection Association (NFPA) 59A, which the DOT incorporated within 49 CFR Part 193. The facilities would be designed to provide safe berthing for the receipt and mooring of LNG vessels and to ensure safe transfer of LNG cargoes from the vessels to the LNG storage tanks.

#### 2.1.1.3 LNG Storage Tanks

The LNG transfer lines would transport the LNG to two 160,000 $m^3$ full containment type tanks, with a primary inner container and a secondary outer container. Figure 2.1-4 is a drawing of a typical full containment storage tank. The tanks would be designed and constructed so that the self-supporting primary container and the secondary container would be capable of independently containing the LNG. The primary container would contain the LNG under normal operating conditions. The secondary container would be capable of containing the LNG (110 percent capacity of inner tank) and of controlling the vapor resulting from unlikely failure of the inner container. The insulated tanks would each be designed to store a net volume of 160,000 $m^3$ (42,267,530 gallons) of LNG at a temperature of -270°F (-168°C) and a maximum internal pressure of 4.3 pounds per square inch gauge (psig).

The double-walled tanks would consist of a:

- 9 percent nickel, steel open top inner container;
- pre-stressed concrete outer container wall;
- reinforced concrete dome roof;
- reinforced concrete outer container bottom; and
- insulated aluminum deck over the inner container suspended from the roof.

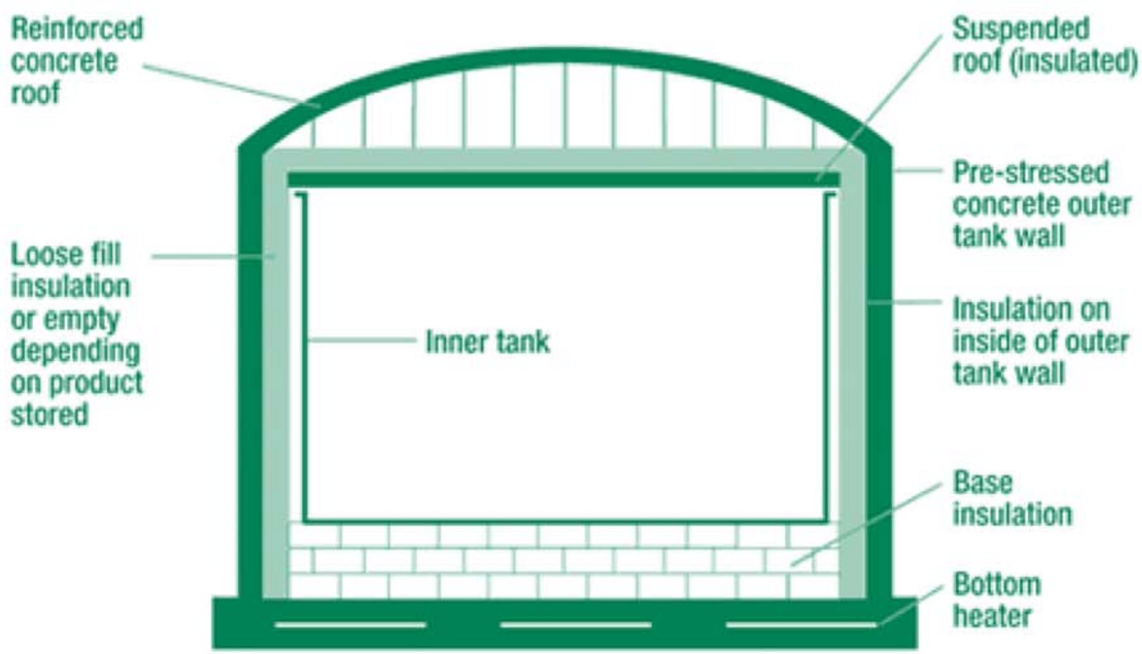



**Figure 2.1-4**
**Downeast LNG Project**
**Typical Full Containment Storage Tank**

The aluminum support deck would be insulated on its top surface with fiberglass blanket insulation material. The diameter of the outer container would be approximately 259 feet. The insulation beneath the inner container would be cellular glass, load-bearing insulation that would support the weight of the inner container and the LNG. The space between the sidewalls of the inner and outer containers would be filled with expanded perlite insulation that would be compacted to reduce long-term settling of the insulation. Base heating would be provided in the foundation to prevent frost heave. The outer container would be lined on the inside with carbon steel plates. This carbon steel liner would serve as a barrier to moisture migration from the atmosphere reaching the insulation inside the outer concrete. This liner also forms the barrier to prevent vapor escaping from inside the tank in normal operation.

There would be no penetrations through the inner container or outer container sidewall or bottom. All piping into and out of the inner or outer containers would enter from the top of the tank. The inner container of each tank would be designed and constructed in accordance with the requirements of American Petroleum Institute (API) Standard 620 and meet the requirements of NFPA 59A and 49 CFR Part 193.

Two fully submerged low pressure transfer pumps would be column mounted in each LNG storage tank. The in-tank pumps would transfer the LNG from the LNG storage tanks to LNG sendout pumps. Each in-tank pump would be designed to handle up to 4,600 gpm. Each pump would be designed for 100 percent sendout capacity and LNG vessel unloading pipeline recirculation.

#### 2.1.1.4 Vaporization System

The SCVs would be installed on land to re-vaporize the LNG to natural gas. In each SCV, natural gas would be fired in a burner, or series of burners, submerged in a water bath. Because the exhaust gases are quenched within the water bath, they operate with a very high (98 to 99 percent) thermal efficiency. The use of an SCV system eliminates the need for withdrawing water from the bay and/or the need to build an on-site power plant to warm (re-gasify) the LNG.

After leaving the vaporizers, the high pressure gas would be metered prior to discharge into the sendout pipeline. A vaporized below grade sendout pipeline would connect between the vaporization system and the metering facilities that would measure the total natural gas output of the LNG project. Under normal operations, the terminal would have an average total output of 500 MMcfd.

#### 2.1.1.5 Vapor Handling System

During normal operations, ambient heat input into the LNG storage tanks and piping system would cause a small amount of LNG to be continuously vaporized, referred to as BOG. Some vaporization of LNG would also be caused by other factors such as barometric pressure changes, heat input due to pumping, and vessel flash vapor. During a vessel unloading, vapor in the LNG storage tank would be displaced by the newly added LNG. The displaced vapor would be returned to the vessel by vapor return blowers through a vapor return line and a vapor return arm connected to the vessel in order to maintain a slight positive pressure in the vessel’s tanks. Additional BOG would be generated due to the heat added by the vessel’s transfer pumps and the heat leaked into the tank and piping systems. Any BOG not returned to the vessel would be compressed by the BOG compressors and condensed in the BOG condenser. The condensers would condense the excess BOG and mix it with the inlet stream to the SCVs.

### 2.1.1.6 Utilities and Support Facilities

Support facilities located within the terminal include an administration building, main control room (MCR), maintenance building/warehouse, utilities building, and a security building.

### 2.1.2 Downeast Sendout Pipeline

The natural gas pipeline facilities proposed by Downeast would consist of a 29.8-mile-long, 30-inch-diameter natural gas sendout pipeline. The sendout pipeline would extend from the LNG terminal to the existing M&NE pipeline system at the Baileyville Compressor Station. The pipeline would be capable of transporting about 500 MMcfd of natural gas at a design pressure of 1,440 psig.

## 2.2 LAND REQUIREMENTS

### 2.2.1 LNG Terminal Facilities

The LNG terminal site would occupy approximately 80 acres of land immediately to the south of Mill Cove in Robbinston, Maine. During early project development Downeast held a purchase option for the entire parcel, and on August 9, 2013 notified the Commission that it exercised the option and has purchased the site. Construction and operation of the proposed LNG terminal would require about 47 acres of land. Construction and operation of Downeast's pier trestle and unloading platform would impact about 3.6 acres of submerged lands in Passamaquoddy Bay, based on the surface area of the pier; however, only 0.1 acre of submerged land would be directly disturbed by the pilings. Downeast must obtain a Submerged Lands Lease from the State of Maine to construct and operate the pier and unloading platform. Downeast intends to file the application for the lease in conjunction with the Maine DEP application, now anticipated in 2014. Table 2.2.1-1 summarizes the land requirements for the proposed LNG terminal. Access to the LNG terminal would be by way of U.S. Route 1.

TABLE 2.2.1-1

**Summary of Land Requirements for the Proposed LNG Terminal Facilities**

| Facility/Use | Land Affected During Construction (acres) | Land Affected During Operation (acres) |
|---|---|---|
| **LNG Terminal** | | |
| Terminal land based facilities a/ | 47.0 a/ | 47.0 |
| Pier trestle and unloading platform | 3.6 | 3.6 |
| **Total** | **50.6** | **50.6** |

a/ Includes sendout pipeline pig launching facility inside the terminal property. Does not include acreage for off-site temporary pipeline and terminal laydown areas. These are included in section 2.2.2.

### 2.2.2 Downeast Sendout Pipeline

Construction of the proposed pipeline and related facilities would disturb about 265.8 acres of land, including a 75-foot-wide construction right-of-way for the 30-inch-diameter sendout pipeline, additional temporary workspaces, pipeline laydown areas, access roads, pipe storage areas, pigging facilities, and mainline valves (MLV).

Operation of the new facilities would require about 138.2 acres, including a 50-foot-wide permanent right-of-way for the 30-inch-diameter pipeline, permanent access roadways, MLV, and pig receiving facility. After construction, the temporary right-of-way would be restored to its previous condition and use. The land required for operation of aboveground facilities would be fenced and maintained by Downeast. Table 2.2.2-1 summarizes the land requirements for the proposed pipeline facilities.

### 2.2.2.1 Pipeline Right-of-Way and Temporary Extra Workspaces

Downeast would construct the 30-inch-diameter sendout pipeline within a 75-foot-wide construction right-of-way, of which 50 feet would be retained for permanent pipeline easement and 25 feet would be temporary workspace. A narrower construction right-of-way ranging from 55 to 65 feet wide would be used in limited site-specific locations, such as along residential areas, existing roadways, and wetlands. Figure 2.2-1 shows a typical right-of-way cross-section for the sendout pipeline. Additional temporary workspace of varying dimensions, located adjacent to the construction right-of-way of the pipeline, would be required at about 141 locations, primarily at crossings of roads, waterbodies, and wetlands. Locations of additional temporary workspaces are listed in table 2.2.2.1-1.

TABLE 2.2.2-1

**Summary of Land Requirements for the Proposed Pipeline Facilities**

| Facility | Land Affected During Construction (acres) | Land Affected During Operation (acres) |
|---|---|---|
| Pipeline | | |
| Pipeline Right-of-Way | 201.3 a/, b/ | 127.5 b/ |
| Additional Temporary Extra Workspaces, including HDD | 18.7 | 0.0 |
| Terminal and Pipeline Off-Site Laydown Areas | 31.7 | 0.0 |
| Access Roads | 10.1 | 10.0 |
| Pipe Storage Area | 3.2 | 0.0 |
| **Subtotal** | **265.0** | **137.5** |
| Aboveground Facilities | | |
| Valve Station | 0.3 d/ | 0.4 e/ |
| Pigging Receiver c/ | 0.5 | 0.3 |
| **Subtotal** | **0.8** | **0.7** |
| **Total f/** | **265.8** | **138.2** |

a/ Includes nominal 75-foot-wide construction right-of-way for the sendout pipeline.
b/ This table only shows the lands that actually would be physically disturbed by the pipeline construction and operation. Areas where HDD is being proposed are excluded because these areas would not be disturbed by construction or operation of the pipeline.
c/ Acreage for the pig launching facility is included in the land requirements for the terminal in table 2.2.1-1. The specific location of the pig receiver and associated interconnection facilities within the M&NE system has not been determined.
d/ The total area disturbed during the valve station construction is 0.5 acre; however, 0.2 acre overlaps the pipeline right-of-way and is included in the pipeline right-of-way acreage.
e/ This is the acreage outside the permanent pipeline right-of-way.
f/ Rounding may result in slight differences in some calculations.

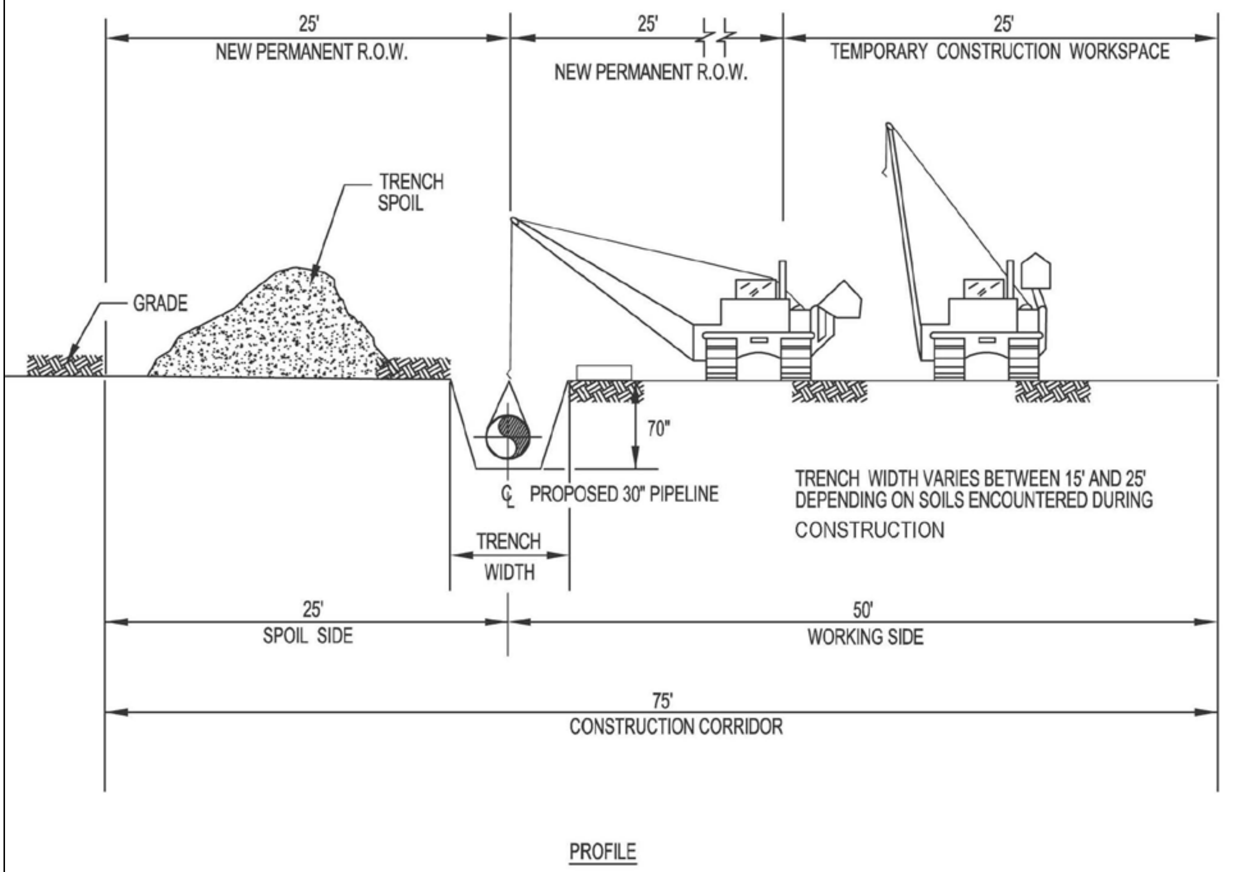



**Figure 2.2-1**
**Downeast LNG Project**
**Typical Sendout Pipeline Right-of-Way Cross Section**

TABLE 2.2.2.1-1

**Additional Temporary Workspace and Laydown Areas for the Downeast LNG Terminal and Sendout Pipeline**

| Location Crossing | Milepost | Acres | Staging Area Type | Existing Land Use |
|---|---|---|---|---|
| Ridge Road | NA | 3.00 | Pipeline and Terminal Laydown Area | Developed / Grassland |
| Route 1 a/ | NA | 2.00 | Pipeline and Terminal Laydown Area | Developed / Grassland |
| Route 1 a/ | NA | 3.00 | Pipeline and Terminal Laydown Area | Developed / Grassland |
| US Route 1 | 0.0 | 0.11 | Road Crossing | Developed / Forest |
| Wetland | 0.1 | 0.11 | Wetland Staging Area | Developed |
| Point of Inflection (PI) | 0.2 | 0.11 | PI Workspace b/ | Forest |
| PI | 0.2 | 0.11 | PI Workspace | Forest |
| Wetland | 0.3 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 0.5 | 0.11 | Wetland Staging Area | Forest |
| Ridge Rd | 0.7 | 0.12 | Road Crossing | Developed / Forest |
| Western Stream | 0.8 | 0.13 | Stream / Wetland Staging Area | Developed / Forest |
| Western Stream | 0.8 | 0.11 | Stream / Wetland Staging Area | Developed / Forest |
| Vernal Pool | 1.0 | 0.86 | Vernal Pool HDD c/ | Forest |
| Vernal Pool | 1.1 | 0.11 | Vernal Pool Staging Area | Wetland |
| Vernal Pool | 1.5 | 0.60 | Vernal Pool Staging Area | Forest |
| Wetland | 1.7 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 1.9 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 2.0 | 0.11 | Wetland Staging Area | Forest |
| Brewer Road | 2.1 | 0.11 | Wetland Staging Area / Road Crossing | Forest / Wetland |
| Sherman Rd | 2.3 | 0.11 | Road Crossing | Developed / Forest |
| Sherman Rd | 2.3 | 0.12 | Road Crossing | Developed / Forest |
| Wetland | 2.4 | 0.11 | Wetland Staging Area | Developed / Forest |
| Wetland | 2.8 | 0.11 | Wetland Staging Area | Forest |
| Vernal Pool | 3.0 | 0.80 | Vernal Pool Staging Area c/ | Forest |
| Vernal Pool | 3.1 | 0.11 | Vernal Pool Staging Area | Forest / Herbaceous |
| Vernal Pool | 3.3 | 0.11 | Vernal Pool Staging Area | Forest / Herbaceous |
| Trimble Rd | 3.5 | 0.11 | Road Crossing | Developed / Forest |
| Vernal Pool | 3.6 | 0.11 | Vernal Pool Staging Area | Forest |
| Vernal Pool | 3.8 | 2.00 | Vernal Pool Staging Area c/ | Forest |
| Vernal Pool | 3.8 | 0.11 | Vernal Pool Staging Area | Forest |
| Inland Wading Bird / Waterfowl Habitat | 4.1 | 0.11 | Inland Wading Bird / Waterfowl Habitat | Forest |
| Inland Wading Bird / Waterfowl Habitat | 4.4 | 0.11 | Inland Wading Bird / Waterfowl Habitat | Forest |
| Shattuck Rd | 5.1 | 0.11 | HDD Staging Area / Road Crossing | Forest |
| Shattuck Rd | 5.1 | 0.40 | HDD Staging Area / Road Crossing | Forest |
| Shattuck Rd | 5.2 | 0.11 | HDD Staging Area / Road Crossing | Forest |
| Shattuck Rd | 5.3 | 0.63 | HDD Staging Area / Road Crossing | Forest |
| PI / Wetland | 5.6 | 0.10 | PI / Wetland Staging Area | Forest |
| Wetland | 6.1 | 0.14 | Wetland Staging Area | Forest |
| PI / Wetland | 6.3 | 0.23 | PI / Wetland Staging Area | Forest |
| PI / Wetland | 6.4 | 0.13 | PI / Wetland Staging Area | Forest |
| Flowed Ponds Stream | 6.7 | 0.10 | Flowed Ponds Stream Habitat / Wetland Staging Area | Forest |
| Flowed Ponds Stream | 6.7 | 0.11 | Flowed Ponds Stream Habitat / Wetland Staging Area | Forest |
| PI | 6.9 | 0.24 | PI Workspace | Forest |
| Wetland | 7.6 | 0.11 | Wetland Staging Area | Developed / Forest |
| Wetland | 7.7 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 7.9 | 0.11 | Wetland Staging Area | Developed / Forest |
| Wetland | 8.0 | 0.11 | Wetland Staging Area | Developed / Forest |
| Inland Wading Bird / Waterfowl Habitat / Wetland | 8.3 | 0.11 | Inland Wading Bird / Waterfowl Habitat / Wetland Staging Area | Forest |
| Inland Wading Bird / Waterfowl Habitat / Wetland | 8.9 | 0.70 | Inland Wading Bird / Waterfowl Habitat / Wetland Staging Area c/ | Forest |
| Inland Wading Bird / Waterfowl Habitat / Wetland | 8.9 | 0.69 | Inland Wading Bird / Waterfowl Habitat / Wetland Staging Area c/ | Forest |
| Vernal Pool | 9.0 | 0.11 | Vernal Pool Staging Area | Forest |

TABLE 2.2.2.1-1

**Additional Temporary Workspace and Laydown Areas for the Downeast LNG Terminal and Sendout Pipeline**

| Location Crossing | Milepost | Acres | Staging Area Type | Existing Land Use |
|---|---|---|---|---|
| Vernal Pool | 9.1 | 0.11 | Vernal Pool Staging Area | Forest |
| Vernal Pool | 9.2 | 0.11 | Vernal Pool Staging Area | Forest / Herbaceous |
| Vernal Pool | 9.3 | 0.57 | Vernal Pool Staging Area c/ | Forest |
| Vernal Pool | 9.3 | 0.12 | Vernal Pool Staging Area | Developed / Forest |
| Vernal Pool | 9.5 | 0.11 | Vernal Pool Staging Area | Developed / Forest |
| Vernal Pool | 9.6 | 0.11 | Vernal Pool Staging Area | Developed / Forest |
| Vernal Pool | 9.6 | 0.51 | Vernal Pool Staging Area c/ | Forest |
| Vernal Pool | 10.4 | 0.11 | Vernal Pool Staging Area | Forest |
| Vernal Pool | 10.4 | 0.76 | Vernal Pool Staging Area c/ | Forest / Herbaceous |
| Vernal Pool | 10.5 | 0.11 | Vernal Pool Staging Area | Forest |
| PI | 10.7 | 0.14 | PI Workspace | Forest |
| PI | 11.7 | 0.22 | PI Workspace | Forest |
| Vernal Pool / Wetland | 11.7 | 0.11 | Vernal Pool / Wetland Staging Area | Forest |
| Vernal Pool / Wetland | 12.2 | 0.11 | Vernal Pool / Wetland Staging Area | Forest |
| Vernal Pool / Wetland | 12.2 | 1.28 | Vernal Pool / Wetland Staging Area c/ | Forest |
| PI | 12.5 | 0.23 | PI Workspace | Forest |
| Vernal Pool / Wetland | 12.7 | 0.63 | Vernal Pool / Wetland Staging Area c/ | Forest |
| Vernal Pool / Wetland | 12.8 | 0.11 | Vernal Pool / Wetland Staging Area | Forest |
| Vernal Pool / Wetland | 12.9 | 0.11 | Vernal Pool / Wetland Staging Area | Forest |
| PI / Wetland | 13.1 | 0.12 | PI / 90° Bend / Wetland Staging Area | Forest / Wetland |
| US Route 1 | 13.7 | 0.11 | Road Crossing | Forest |
| US Route 1 | 13.8 | 0.11 | Road Crossing | Forest |
| Railroad Crossing | 14.0 | 0.13 | Railroad Crossing / Wetland Staging Area | Agricultural |
| Railroad Crossing | 14.1 | 0.11 | Railroad Crossing | Agricultural / Developed / Forest |
| St. Croix River | 14.1 | 1.65 | St. Croix River | Agriculture / Developed / Herbaceous |
| St. Croix River | Near 15.2 | 3.18 | St. Croix River d/ | Forest / Wetland |
| St. Croix River | 15.4 | 1.14 | St. Croix River | Forest / Wetland |
| St. Croix River | 15.4 | 4.35 | St. Croix River c/ | Forest |
| Railroad Crossing | 15.5 | 0.90 | Railroad Crossing | Forest |
| Railroad Crossing | 15.6 | 0.23 | Railroad Crossing | Forest / Wetland |
| PI / Wetland | 16.2 | 0.13 | PI / Wetland Staging Area | Herbaceous |
| PI / Wetland | 16.4 | 0.21 | PI / Wetland Staging Area | Forest / Wetland |
| Wetland | 16.6 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 16.8 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 17.2 | 0.11 | Wetland Staging Area | Developed / Forest |
| Wetland | 17.4 | 0.11 | Wetland Staging Area | Forest |
| Inland Wading Bird / Waterfowl Habitat | 17.7 | 0.38 | Inland Wading Bird / Waterfowl Habitat | Developed / Forest / Herbaceous / Wetland |
| Inland Wading Bird / Waterfowl Habitat | 18.2 | 0.11 | Inland Wading Bird / Waterfowl Habitat | Forest |
| Inland Wading Bird / Waterfowl Habitat | 18.2 | 1.87 | Inland Wading Bird / Waterfowl Habitat | Forest |
| Wetland | 18.6 | 0.11 | Wetland Staging Area | Developed / Forest |
| Wetland | 19.1 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 19.5 | 0.11 | Wetland Staging Area | Developed / Herbaceous |
| Wetland | 19.7 | 0.11 | Wetland Staging Area | Forest / Herbaceous |
| PI | 19.8 | 0.13 | PI Workspace | Forest / Herbaceous |
| US Route 1 | 20.1 | 0.12 | Road Crossing | Developed / Herbaceous |
| US Route 1 | 20.1 | 0.14 | Road Crossing | Agricultural / Developed |
| PI | 20.3 | 0.14 | PI Workspace | Forest |
| Wetland | 20.6 | 0.11 | Wetland Staging Area | Forest |
| Town Rd | 20.9 | 0.13 | Road Crossing | Developed / Forest |
| Town Rd | 20.9 | 0.11 | Road Crossing | Agricultural / Developed / Forest |
| Wetland | 21.2 | 0.11 | Wetland Staging Area | Forest |
| Wapsaconhagan Brook | 21.3 | 0.11 | Wetland Staging Area / Stream | Forest |
| Wapsaconhagan Brook | 21.3 | 0.34 | Wetland Staging Area / Stream | Forest |

TABLE 2.2.2.1-1

**Additional Temporary Workspace and Laydown Areas for the Downeast LNG Terminal and Sendout Pipeline**

| Location Crossing | Milepost | Acres | Staging Area Type | Existing Land Use |
|---|---|---|---|---|
| Wapsaconhagan Brook | 21.3 | 0.11 | Wetland Staging Area / Stream | Forest |
| PI | 21.7 | 0.13 | PI Workspace | Herbaceous |
| South Princeton Rd | 22.1 | 0.11 | Road Crossing | Forest / Herbaceous / Wetland |
| South Princeton Rd | 22.2 | 0.11 | Road Crossing | Forest / Herbaceous / Wetland |
| PI / Wetland | 22.2 | 0.14 | PI / Wetland Staging Area | Forest |
| Wetland | 22.3 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 22.6 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 22.6 | 0.11 | Wetland Staging Area | Developed / Forest |
| Private Road | 22.8 | 0.11 | Private Road / Wetland Staging Area | Developed / Forest |
| Wetland | 23.1 | 0.11 | Wetland Staging Area | Developed / Forest |
| PI / Wetland | 23.4 | 0.11 | PI / Wetland Staging Area | Developed / Forest |
| Wetland | 23.6 | 0.11 | Wetland Staging Area | Forest |
| PI | 23.9 | 0.11 | PI Workspace | Developed |
| Vernal Pool | 24.2 | 0.46 | Vernal Pool Staging Area c/ | Developed |
| Vernal Pool | 24.4 | 0.11 | Vernal Pool Staging Area | Wetland |
| PI / Wetland | 24.8 | 0.11 | PI / Wetland Staging Area | Developed / Forest |
| Inland Wading Bird / Waterfowl Habitat | 24.9 | 1.26 | IWWH HDD Staging c/ | Forest |
| Inland Wading Bird / Waterfowl Habitat | 25.1 | 0.11 | Inland Wading Bird / Waterfowl Habitat | Forest |
| Inland Wading Bird / Waterfowl Habitat | 25.6 | 0.15 | Inland Wading Bird / Waterfowl Habitat | Forest / Wetland |
| PI / Wetland | 25.7 | 0.13 | PI / Wetland Staging Area | Forest / Wetland |
| PI / Wetland | 25.9 | 0.14 | PI / Wetland Staging Area | Forest / Wetland |
| Wetland | 26.6 | 0.11 | Wetland Staging Area | Developed / Forest |
| Wetland | 27.0 | 0.11 | Wetland Staging Area | Developed / Forest |
| US Route 1 | 27.2 | 0.11 | Road Crossing | Developed / Forest |
| PI / Wetland | 27.3 | 0.21 | PI / Wetland Staging Area | Forest / Wetland |
| Wetland | 27.5 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 27.7 | 0.11 | Wetland Staging Area | Forest |
| Wetland | 28.3 | 0.11 | Wetland Staging Area | Forest |
| Grand Falls Rd | 28.7 | 0.09 | Road Crossing | Developed / Forest |
| Grand Falls Rd | 28.7 | 0.11 | Road Crossing | Developed / Forest |
| Inland Wading Bird / Waterfowl Habitat | 28.7 | 1.08 | Inland Wading Bird / Waterfowl Habitat | Forest |
| Wetland | 28.8 | 0.11 | Wetland Staging Area | Forest |
| Inland Wading Bird / Waterfowl Habitat | 28.8 | 0.11 | Inland Wading Bird / Waterfowl Habitat | Forest |
| Inland Wading Bird / Waterfowl Habitat | 29.0 | 0.11 | Inland Wading Bird / Waterfowl Habitat | Forest |
| Vernal Pool | 29.0 | 0.65 | Vernal Pool Staging Area c/ | Forest |
| Vernal Pool | 29.1 | 0.11 | Vernal Pool Staging Area | Forest |
| Vernal Pool | 29.3 | 0.11 | Vernal Pool Staging Area | Forest / Wetland |
| Wetland | 29.5 | 0.11 | Wetland Staging Area | Developed / Forest |
| Vernal Pool | 29.6 | 0.57 | Vernal Pool Staging Area c/ | Herbaceous |
| Vernal Pool | 29.7 | 0.11 | Vernal Pool Staging Area | Forest |
| Vernal Pool | 29.8 | 0.11 | Vernal Pool Staging Area | Developed |
| Vernal Pool | 29.8 | 0.11 | Vernal Pool Staging Area | Developed |

a/ These laydown areas would be located on the west side of U.S. Route 1, approximately 3,000 feet south of the proposed site entrance.
b/ PI (Point of Inflection, the point of change on curve) workspace is the extra workspace required where the pipeline turns or bends in a different direction.
c/ Sendout pipeline laydown areas.
d/ Pipe storage area.

Although Downeast has identified areas where extra workspace would be required, additional or alternative areas could be identified in the future due to changes in site-specific construction requirements. Downeast would be required to file information on each of those areas for review and approval prior to use.

Approximately 12 miles of the route for the sendout pipeline would be adjacent to existing rights-of-way. Table 2.2.2.1-2 lists locations where the pipeline would parallel existing rights-of-way. Downeast stated that it would coordinate with Eastern Maine Electric Cooperative (EMEC) on the use of their transmission line right-of-way for a portion of the pipeline right-of-way. If feasible, where the pipeline would be directly adjacent to the existing right-of-way, the new pipeline would be offset about 5 to 10 feet from the outside edge of the existing utility right-of-way. The 50-foot-wide permanent pipeline right-of-way, as well as a portion of the construction right-of-way, would partially overlap the existing electric transmission line right-of-way. **We recommend that:**

- **Downeast should not begin construction of the pipeline from milepost (MP) 17.7 to MP 27.2 until Downeast files with the Secretary, for review and written approval by the Director of OEP, updated alignment sheets, developed in coordination with EMEC, depicting the pipeline adjacent to the existing transmission line.**

It is anticipated that the new electric transmission line that would be constructed by EMEC to service the terminal would be installed parallel to the pipeline from MP 0.2 to MP 11.6. The new transmission line would bring electric power from EMEC's existing switchyard in Milltown to a new electric substation that would be located across U.S. Route 1 from Downeast's LNG terminal. These are nonjurisdictional facilities that are discussed in section 2.9.

TABLE 2.2.2.1-2

**Locations Where the Downeast Sendout Pipeline Would Parallel Existing Rights-of-Way**

| Mileposts | Segment Length (miles) | Existing Easement | Direction from Existing Right-of-Way |
|---|---|---|---|
| 17.7-27.2 | 9.5 | Existing EMEC Powerline | Adjacent to the south side of the electric transmission line |
| 27.3-29.8 | 2.5 | Existing M&NE Pipeline | Adjacent to the south side of the pipeline |

### 2.2.2.2 Aboveground Facilities

Aboveground facilities associated with the proposed pipeline would include three MLVs and pigging and gas metering facilities. Table 2.2.2-1 lists the land requirements for these facilities along the sendout pipeline. The pig launching facility and MLV at MP 0.0 would be located in the terminal site and would require approximately 0.25 acre for both construction and operation and is included within the 47 acres of land associated with the terminal construction and operation. The MLV at MP 17.17 would require approximately 0.5 acre for construction and 0.4 acre for permanent operation. The valve station is accessible from Haywood Lane, eliminating the need for an access road. The pig receiving and gas metering facilities and an MLV would be located at MP 29.8 within the Baileyville Compressor Station property boundary and would require 0.5 acre for construction and 0.3 acre during operation.

### 2.2.2.3 Access Roads and Contractor Yard

Access roads would be located within the pipeline construction right-of-way where possible. Downeast would use four temporary access roads related to its proposed pipeline facilities (see table 2.2.2.3-1). Only the access road at MP 15.4 is a newly created access road that would require clearing for a new road base. The other three access roads are existing skidder roads that were previously used for timbering activities. These skidder access roads have existing road bases; however, they would need to be upgraded prior to construction of the sendout pipeline. The width of the skidder roads is generally 15 to 25 feet, with numerous road segments exceeding 25 feet in width. The roads are compacted earth with a gravel surface and are raised above existing grade for positive drainage control. Replacing and supplementing the gravel surface that has degraded over time would be the principle improvement to upgrade the skidder roads for construction of the sendout pipeline. Small, localized sections of the skidder roads may need to be widened. A total of about 10.2 acres would be required for the construction access roads. After the pipeline construction activities are completed, the skidder roads would not be restored to pre-existing conditions; however, the soils and vegetation disturbed by widening would be rehabilitated. The road improvements would be left in place to assist local timbering operators for forestry equipment access for future timber harvest.

Downeast has identified 20 proposed pipeline and terminal laydown areas and a pipe storage yard, which would affect approximately 30.9 acres during the construction of the terminal and sendout pipeline (see table 2.2.2.1-1). These tracts would only be used temporarily during construction of the project. Following construction, these areas would be returned to their pre-construction conditions.

TABLE 2.2.2.3-1

**Access Roads Associated with the Proposed Pipeline**

| **Milepost** | **Road Name/ Destination** | **New/ Existing** | **Permanent/ Temporary** | **Acres Affected** |
|---|---|---|---|---|
| 5.2 | Shattuck Road to MP 6.2 on the pipeline | Existing | Permanent | 4.1 |
| 8.1 | Carson Road to MP 8.1 on the pipeline | Existing | Permanent | 3.1 |
| 10.2 | Hardscrabble Road to MP 9.3 on the pipeline | Existing | Permanent | 2.6 |
| 15.4 | Private Road to MP 15.4 staging area + pipe laydown area | New | Permanent | 0.4 |

## 2.3 CONSTRUCTION PROCEDURES

This section describes the general construction procedures proposed by Downeast for construction of the LNG terminal and sendout pipeline facilities. Section 4.0 of this EIS contains more detailed discussions of proposed construction and restoration procedures, as well as additional measures that we are recommending to mitigate environmental impacts.

The LNG terminal and sendout pipeline facilities would be designed, constructed, operated, and maintained in accordance with federal standards that are intended to ensure adequate protection for the public and to prevent LNG and natural gas pipeline failures or accidents.

Under provisions of the Natural Gas Pipeline Safety Act of 1968, as amended, Downeast would design, construct, operate, and maintain the LNG terminal facilities in accordance with the DOT's *Federal Safety Standards for Liquefied Natural Gas Facilities* at 49 CFR 193 and the NFPA's *Standards for the Production, Storage, and Handling of LNG* (NFPA 59A). These standards specify siting, design, construction, equipment, and fire protection requirements for new LNG facilities. The LNG vessel unloading facilities and any appurtenances located between the LNG vessel and the last valve immediately before the LNG storage tank would comply with the applicable sections of the Coast Guard regulations for *Waterfront Facilities Handling LNG* at 33 CFR 127 and Executive Order 10173.

The proposed pipeline facilities would be designed, constructed, operated, and maintained in accordance with the DOT regulations at 49 CFR 192, *Transportation of Natural or Other Gas by Pipeline: Minimum Federal Safety Standards*. Among other items, these regulations specify material selection, design criteria, corrosion protection, and qualification for welders and operation personnel. In addition, Downeast would comply with the Commission's regulations at 18 CFR 380.15, regarding the siting and maintenance of pipeline rights-of-way.

Downeast would construct the project facilities in accordance with the FERC's *Upland Erosion Control, Revegetation and Maintenance Plan* (Plan), *Wetland and Waterbody Construction and Mitigation Procedures* (Procedures) and M&NE's *Soil Erosion and Sediment Control Guidelines* (excluding Appendices) used to construct the Phase II Pipeline Project in northeastern Maine. The FERC's Plan and Procedures are available for viewing on the FERC Internet website at www.ferc.gov. The M&NE Guidelines are provided in Appendix H. Since Downeast has adopted the FERC Plan and Procedures, and the M&NE *Soil Erosion and Sediment Control Guidelines*, they will be hereafter referred to as Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*. Prior to construction, Downeast would prepare an Environmental Control Plan (ECP) that would include its Plan and Procedures, and *Soil Erosion and Sediment Control Guidelines* as well as other applicable federal, state, and local requirements.

Downeast would be required to develop onshore and offshore Spill Prevention, Control and Countermeasure Plans (SPCC Plans) to be implemented during construction of the facilities. The SPCC Plans must address potential spills of fuel, lubricants, and other hazardous materials and describe spill prevention practices, spill handling and emergency notification procedures, and training requirements.

### 2.3.1 LNG Terminal Facilities

Downeast considered the following factors during site selection and design of the LNG terminal facilities in accordance with 49 CFR 193 Subpart B and 33 CFR 127:

- flammable vapor dispersion, thermal radiation protection and separation of facilities;
- seismic forces and soil characteristics; and
- wind forces and other severe natural conditions.

Construction of the LNG terminal facilities would include site preparation, activities associated with construction of the pier trestle, unloading platform, LNG storage tanks, and vaporization and support facilities.

#### 2.3.1.1 Site Preparation

To prepare the terminal site for construction, areas of the onshore facilities that would be disturbed by construction activities would be stabilized with temporary erosion controls, which would be maintained until construction is complete. Approximately 47 acres would be cleared and grubbed as needed for construction.

Off-site staging areas would be used for some fabrication, employee parking, and material/equipment storage.

The near-surface competent bedrock would preclude the need for deep foundations or extensive excavations. The cut/fill balance is expected to remain on-site. The only fill that Downeast may be required to import is structural stone for some of the foundations and possibly the on-site roads. Downeast states that there appears to be adequate existing resources in the region to provide fill, without the need to develop a new fill resource for the LNG project. However, if a new fill source is required, Downeast would file the necessary information with the Commission for review and approval.

Some of the larger materials needed for the LNG terminal would be delivered to the project site and constructed from working marine barges. All other required materials would be transported to the site via truck.

#### 2.3.1.2 LNG Berthing, Vessel Unloading, and Transfer Facilities

A 3,862-foot-long pier equipped with mooring systems and accessories would be constructed for the berthing and unloading of LNG vessels. The LNG pier trestle construction would be accomplished using a combination of "over the top" construction method using land-based equipment working from the pier as it is constructed, and off-shore marine-based equipment. The "over the top" method utilizes a temporary (movable) steel frame, supported on the permanent pilings as they are installed, to support the crane. The crane would be moved along the pier as pilings are installed so that bottom impacts would be limited to the location of each piling. As the pier construction progresses into deeper water, the construction methodology would switch to marine-based equipment that utilizes a jack-up barge to install the remaining portion of the trestle and unloading platform. This construction method would minimize the use of barge-mounted equipment, resulting in a substantial reduction of impacts on the seabed from anchoring and from propeller wash.

Large diameter, steel pipe piles are anticipated to be used to support the trestle and loading platform. These piles would be vibrated and driven through any surficial soils on the seabed to the top of the underlying rock where they would be seated into competent bedrock. The piles would be anchored into the bedrock using drilled rock sockets. Rock sockets would be constructed using rotary auger methods. Impact driving would only be required to embed or "seat" the piles into the top of the bedrock, likely only a few feet, to seal the bottom of the piles into the rock so that rock sockets can be installed. The LNG mooring and breasting dolphins would be constructed using floating or jack-up marine-based equipment. The dolphins would either be comprised of multiple steel pipe piles supporting a large concrete cap, or a very large single steel-pipe type dolphin (monopile). The piles would be similarly driven through any surficial soils, if any, at the seabed until the top of rock is encountered. The piles would then be seated and affixed to the rock using drilled rock sockets. A precast concrete form would be used to contain the cast-in-place concrete used for the remainder of the pile cap. Finally, the fenders, mooring hooks, and other topside equipment (railing, ladders, lights, etc.) would be installed.

Once the loading platform and breasting and mooring dolphins are in-place, fabricated steel truss walkways would be erected by the marine equipment to interconnect the structures for personnel access and operations.

The following would also be incorporated into the design of the unloading platform:

- a pier jetty control room (JCR) providing control and monitoring capabilities remotely from the MCR during vessel unloading operations;
- a facility firefighting system extended to the unloading berth;
- a gangway to allow access to/from the LNG vessel for customs and immigration officials, pilots, operations personnel (including unloading supervisor), and crew members;
- gangways between the unloading platforms and berthing dolphins for use by line handlers during the berthing and unberthing of LNG vessels; and
- an LNG spill trough beneath the unloading platform and LNG transfer pipe to route any LNG spills to the terminal's LNG spill containment system. This would be designed in accordance with the requirements of NFPA 59A Section 5.2.

#### 2.3.1.3 LNG Storage and Vaporization Facilities

The most labor-intensive and time-consuming activity would be the construction of the LNG storage tanks. The two 160,000 $m^3$ full containment LNG storage tanks would be built on a ground reinforced concrete slab foundation. The preparation of the ground for the installation of the LNG storage tank foundation would take approximately seven months. Once the ground is prepared, approximately four months would be required to install the foundation; following which, the construction of the LNG storage tank would take approximately 20 months to complete.

Construction of the LNG storage tank and foundation would include the following key activities:

- prepare and level the area upon which the LNG storage tank and foundation would be located;
- form and pour the concrete foundation; the tank base heating elements would be installed within the poured concrete;
- construct the outer tank carbon steel liner, install the outer tank carbon steel bottom liner on the foundation, erect the outer tank carbon steel roof liner on the outer tank bottom, and erect the inner tank suspended deck and connect to the steel roof;
- raise the outer tank steel roof and suspended deck using an air lift procedure and weld to the top compression bar;
- install the tank bottom insulation;
- install the secondary tank and inner tank bottoms;
- erect the inner tank shell;
- construct the outer tank concrete walls;
- install the outer tank concrete roof;
- install and tension concrete wall pre-stress tendons;
- install tank internal accessories, such as pump columns, bottom and top fill pipework, instrument wells, purge and cool-down pipework;
- install tank external accessories, such as tank instrumentation, electrical equipment, pipework, roof platforms, and access stairways;
- hydrotest the inner tank and, once complete, air dry the tank;

- final installation of the tank internal and annual space instrumentation;
- install tank insulation (once tank is completely dry);
- complete visual inspections and conduct final tank clean;
- install in-tank LNG pumps; and
- purge tank with nitrogen to a positive pressure and prepare for cool-down.

The storage tanks would be hydrostatically tested in accordance with API Standard 620, Appendix Q.8. API Standard 620 deals with the design and construction of large, welded, field-erected low-pressure carbon steel aboveground storage tanks (including flat-bottom tanks) with a single vertical axis of revolution, and Appendix Q deals with low-pressure storage tanks for liquefied hydrocarbon gases at temperatures not lower than -270°F (-168°C) (Techstreet 2008). Hydrostatic testing of each tank would involve filling the inner tank with approximately 28 million gallons of water. Water used for the hydrostatic testing of the first tank would be used for the hydrostatic testing of the second tank. The tank would be filled and emptied as quickly as possible. At the maximum level calculated, the water would be maintained for at least 48 hours for inspection. After testing, the tank would be cleaned with fresh water and dried. Test water would be obtained from on-site water wells, commercial providers, or the adjacent waterways. The water would be sampled and analyzed prior to discharge. See section 4.3.2.1 of this EIS for further information on hydrostatic testing.

### 2.3.2 Pipeline and Associated Aboveground Facilities

#### 2.3.2.1 General Pipeline Construction Procedures

Figure 2.3-1 shows the typical steps of cross-country pipeline construction. Standard pipeline construction proceeds in a manner of an outdoor assembly line composed of specific activities that make up the linear construction sequence. These operations collectively include survey and staking of the right-of-way, clearing and grading, trenching, pipe stringing and bending, welding and coating, lowering-in and backfilling, hydrostatic testing, and cleanup. In addition to standard pipeline construction, Downeast would use special construction techniques where warranted by site-specific conditions. These special techniques would be used when constructing across residential areas, waterbodies, wetlands, and roads.

**Survey and Staking**

All areas to be affected by pipeline construction would be mapped and flagged well in advance of actual construction activity. Important resource protection areas, such as stream crossings, wetlands, deer wintering areas (DWAs), inland waterfowl and wading bird habitat (IWWH), and significant vernal pools (SVPs), would be specifically marked and flagged, as well as posted with signage. Prior to actual field work by the pipeline crews, the Environmental Inspector(s) (EI) would guide the crew management personnel on a site-by-site review of the mapped and protected areas. Construction restrictions and management methods designed to protect the specified areas would be specifically reviewed with the pipeline crews prior to construction.

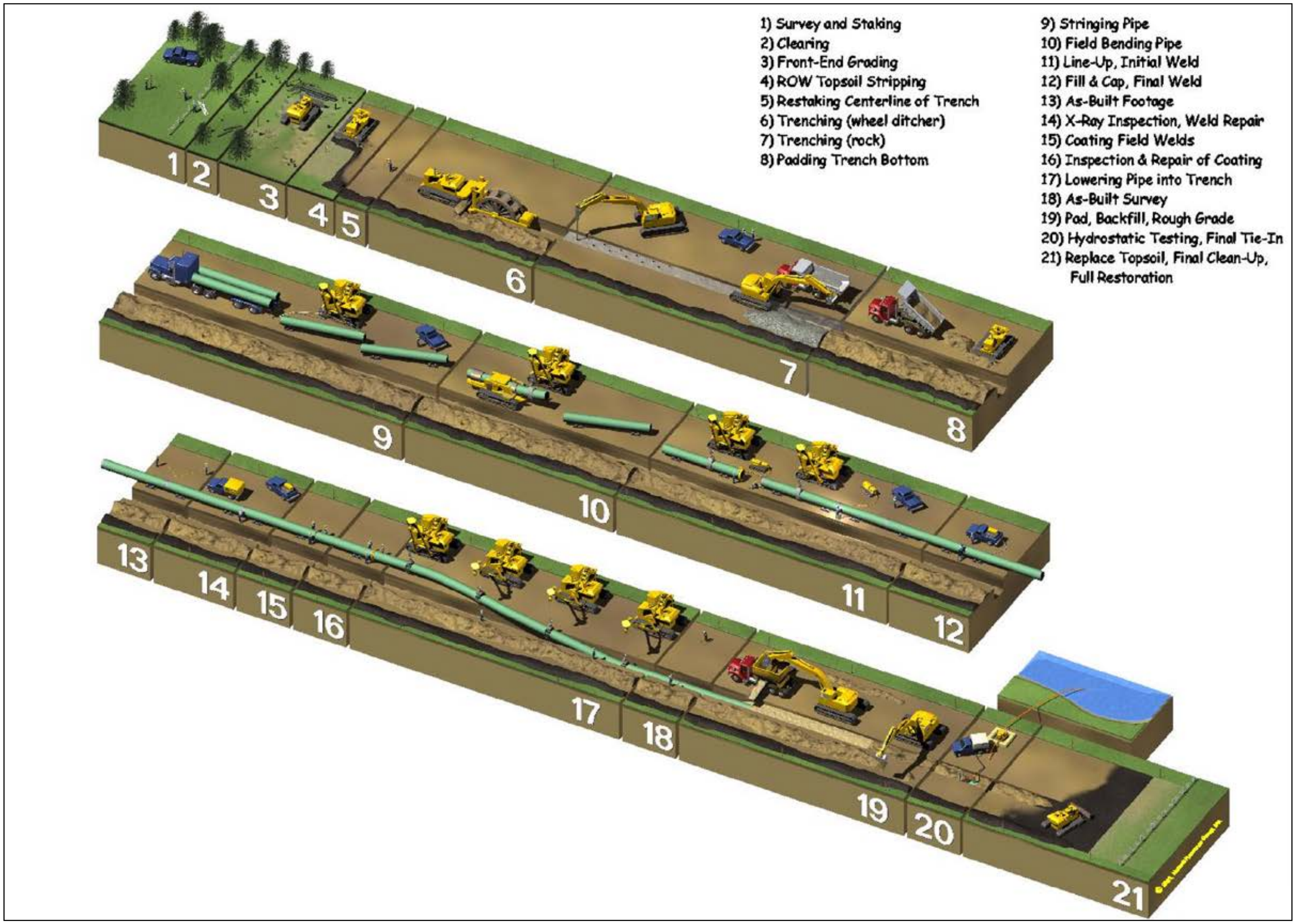



**Figure 2.3-1**
**Downeast LNG Project**
**Typical Pipeline Construction Sequence**

## Clearing and Grading

Where necessary and unavoidable, the right-of-way would be cleared of vegetation and rough-graded to specified widths. Clearing and grading in temporary workspaces would be limited to encourage natural revegetation. Vegetative or other waste removed from the pipeline right-of-way would be properly disposed of in accordance with applicable permit conditions. Erosion controls would be installed as soon as possible after initial clearance and disturbance of an area's surface soils.

## Trenching

Trench excavation widths and depths would be predetermined prior to the start of pipeline construction. Typically, excavation would be limited to the depth required to allow for the burial of the pipe plus 3 feet of cover in soil areas as required by 49 CFR Part 192. Typically, the trench would be about 6 feet deep (for a minimum of 3 feet of cover over the pipe) and between 10 to 25 feet wide. The depth of the pipeline should prevent any impacts from frost heaves. The pipeline ditch would be excavated with either a rotary trencher or track-mounted backhoe.

To avoid or minimize the mixing of topsoils with subsoils, topsoil segregation methods would be conducted as specified in Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*, agency requirements, or landowner specifications.

## Pipe Stringing, Bending, and Welding

Pipeline crews would "string" the pipe sections to be lain in a trench area along previously specified points. Pipe sections would be off-loaded from trucks and placed in the stringing area using side-boom equipment or other suitably capable equipment. The pipe sections would then be lined up end to end to allow for welding and bending into continuous lengths. Pipe welding would be performed in accordance with API Standard No. 1104 (most current revision). Quality assurance/quality control (QA/QC) would be conducted in accordance with 49 CFR Part 192.

## Lowering-In and Backfilling

Coated and inspected pipe lengths would be lowered into prepared trenches. After the pipeline has been placed in the trench, the pipeline would be covered with a soil material padding that acts as a buffer between the pipeline and the backfill. The remainder of the trench would be backfilled with suitable soil material. Ideally, the material that was excavated for the trench would be used as backfill. Where the material is not suitable as backfill, imported material would be used. The trench may be over-backfilled to allow for additional settlement over time. Once the pipeline has been installed, it would be cleaned out of loose impediments that may have been left over from the installation process by using compressed air-driven manifolds.

## Hydrostatic Testing

After cleaning and prior to service, the pipeline would be tested in accordance with 49 CFR Part 192. The test consists of placing the pipeline under hydrostatic pressure to verify its structural integrity for its design pressure load. If a leak or break in the line were to occur during testing, Downeast would repair and retest that section of pipe until the DOT specifications are met. After testing is completed, the water would be discharged in accordance with Maine

Pollutant Discharge Elimination System (Maine PDES) permit requirements. Hydrostatic testing is addressed further in section 4.3.2.2 of this EIS.

**Cleanup and Restoration**

Following backfilling, all work areas would be final-graded and restored to pre-construction contours as closely as possible. Prior to final grading, all construction debris would be picked up along the right-of-way. Permanent erosion control structures, such as slope breakers, would be installed during final grading, in accordance with Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*. Downeast would restore the work areas within one week after the trench has been backfilled and graded. In addition, restoration of wetlands would be conducted in accordance with Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*, and any COE permit conditions. Private property such as fences, field roads, and driveways would be restored or repaired as necessary.

Revegetation would be accomplished by seeding disturbed areas with native seed mixtures in accordance with the recommendations of the local office of the Natural Resources Conservation Service (NRCS) or as requested by the landowner. Revegetation is further discussed in section 4.4.2 of this EIS.

All construction work areas would be monitored for the success of revegetation and restoration. Inspections would be conducted after: (1) initial regrading, stabilization, and reseeding; (2) at the beginning and latter parts of the first full growing season; and (3) during the second growing season. Restoration and revegetation success evaluations would be based on predetermined criteria established in Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* and with the various agencies and expressed as conditions in relevant permits and approvals.

### 2.3.2.2 Special Pipeline Construction Techniques

**Utility and Road Crossings**

Prior to construction, Downeast would contact the local Dig Safe system to determine the location of utilities to be crossed. These utility crossings would then be marked in the field during pre-construction surveys.

Paved roads would be crossed using a bore. For the bore method, pits would be excavated on both sides of the road at the depth of the ditch. A boring machine uses an auger to drill a tunnel under the road, wide enough for the pipeline and casing to be pulled through. Unpaved county roads would be open-cut. During the cut, usually one lane of traffic would be left open. Steel plates may be used to cover the open trench.

Utility and road crossings would be done according to applicable permits. Local authorities would be kept apprised of the timing of such crossings. Roadway surfaces would be restored in a timely fashion according to state and local specifications.

**Residential Areas**

The draft EIS described 19 residences that would be within 50 feet of the permanent right-of-way. Downeast subsequently revised its pipeline route and work areas to increase the distance between the residences and construction work areas. There are now only two residences located approximately 50 feet from the construction right-of-way. Construction in residential areas would employ several construction practices to protect public safety and minimize disturbance of these areas. These practices include:

- installing safety fencing along the edge of the permanent right-of-way out to a distance of 100 feet on either side of the residence;
- preparing access and establishing environmental protection devices in accordance with Best Management Practices (BMPs);
- immediate restoration of driveways, lawn areas, and landscaping within the construction work areas except where required for continued construction access; and
- immediate restoration of all remaining areas following final restoration.

A more detailed discussion of the route variations and residential areas can be found in sections 3.8.2.2 and 4.7.2.3, respectively.

**Wetlands and Waterbodies**

Downeast would construct the project facilities in accordance with Downeast's Procedures and *Soil Erosion and Sediment Control Guidelines*. For conventional wetland crossings, Downeast would segregate the top 12 inches of topsoil. When crossing saturated wetlands, Downeast would use wooden swamp mats to minimize the disturbance to wetland soils.

Most stream crossings would be open-cut using excavation equipment and the dam and pump crossing method. The dam and pump crossing method is a dry-crossing technique that uses pumps to isolate water from the construction area. Downeast proposes to cross SVPs and selected rivers with riffle pools with horizontal directional drill (HDD) to avoid or minimize impacts to these sensitive environmental resources. A more detailed discussion of waterbody and wetland construction can be found in sections 4.3.2 and 4.4.1 of this EIS, respectively.

**Rock Blasting and Rugged Topography**

Rock encountered during construction would be removed using various techniques, including conventional backhoe excavation, dozer ripping and backhoe excavation, use of a backhoe hammer and backhoe excavation, or blasting and backhoe excavation. Excess rock would be windrowed on the right-of-way with landowner permission, or removed to an off-site approved rock disposal area. Blasting activity would be performed by licensed professionals according to strict guidelines designed to control energy release. Blasting is discussed further in section 4.1.1.2 of this EIS.

The proposed sendout pipeline does not cross through any areas of steep side slopes that would require special construction techniques. Construction along moderate side slopes would be necessary. Permanent trench breakers consisting of sandbags would be installed in trenches over and around the pipe in areas of slope with the potential for erosion.

### 2.3.2.3 Aboveground Facility Construction Procedures

Three MLVs and two pigging facilities would be constructed for the sendout pipeline. The MLV and pig launching facility at the start of the sendout pipeline would be constructed within the LNG terminal site. The MLV at MP 17.17 north of U.S. Route 1 would require approximately

0.3 acre for construction and 0.4 acre for permanent operation. The MLV and pigging facilities at the terminus of the sendout pipeline would be located at MP 29.8 within the Baileyville Compressor Station property boundary.

## 2.4 CONSTRUCTION SCHEDULE

Downeast anticipates that construction of the entire project would take a total of about 35 months. The first part of this process would be terminal site work and foundation preparation for the LNG storage tanks. Once the tank foundations are in place, work would begin on tank construction, terminal buildings, and the marine terminal. It is anticipated that the LNG storage tank construction would take approximately 30 months from the start of site work. The other terminal facilities would be constructed in approximately 18 months with marine construction taking approximately 16 months. Sendout pipeline construction would take approximately 9 to 12 months.

## 2.5 ENVIRONMENTAL COMPLIANCE AND MONITORING

Downeast would implement environmental compliance and monitoring requirements from its Plan and Procedures and the *Soil Erosion and Sediment Control Guidelines* during construction of the LNG terminal and sendout pipeline. Downeast would also incorporate compliance and monitoring requirements from federal, state, and local permits obtained for the project.

Downeast would conduct mandatory environmental training for all relevant Downeast and contractor personnel involved with construction of the import terminal and pipeline facilities. Downeast would employ at least one EI for construction of the LNG terminal, and at least one EI for construction of the pipeline. The EIs would be responsible for monitoring construction activities for compliance with the conditions of the FERC Certificate, and all other applicable federal, state, and local permits. The EIs would have independent status, but would report to the Lead Downeast Inspector, and would have stop-work authority in the event of a noncompliance issue that requires corrective action.

The FERC and its own independent EIs would monitor the project for compliance with the Commission's environmental conditions. In addition, Downeast would comply with Maine DEP requirements and employ third-party inspectors to ensure that erosion control and other environmental safeguards are in place and maintained during construction.

## 2.6 OPERATION AND MAINTENANCE

### 2.6.1 LNG Terminal Facilities

According to Downeast, imported LNG would be obtained from unspecified liquefaction plants throughout the world (e.g., Trinidad, Nigeria, Qatar, Algeria, Oman, Abu Dhabi, and Libya) and delivered via LNG vessels to the proposed terminal. LNG vessels would be under the control of local pilots during the LNG marine transit to and from the terminal. In accordance with the WSR recommendations, the attending pilots would decide, in consultation with and the concurrence of the COTP, whether the weather, current, visibility, and wind conditions allow safe entry to the harbor. Based on recommendations in the WSR, LNG vessels would be escorted by three to four assist tugs (depending on vessel size) to provide assistance in the unlikely event of a mechanical failure to the LNG vessel or during adverse weather conditions, with one tug tethered at all times during the transit to the terminal. The WSR also recommends that authorized Coast Guard vessels escort the LNG vessels during transit. In addition, the WSR recommends that a standby tug be moored outboard of the berthed LNG vessel during its stay at the terminal.

Upon arrival at the terminal, the vessel would be berthed using a site-specific vessel approach system and secured with a mooring system equipped with a line monitoring system to continuously monitor tension of all mooring lines. The vessels would use onboard pumps to transfer the LNG at approximately -270°F (-168°C) through the unloading arms and insulated pipe to the LNG storage tank at a rate of approximately 14,000 cubic meters per hour ($m^3$/hr).

During vessel unloading, vapor in the LNG storage tank would be displaced by the newly added LNG. The displaced vapor would be returned to the vessel by vapor return blowers through a vapor return line and a vapor return arm connected to the vessel in order to maintain the pressure in the vessel's tanks. Additional BOG would be generated due to the heat added by the vessel's transfer pumps and the heat leak into the tank and piping systems. Any BOG not returned to the vessel would be compressed by the BOG compressors and condensed in the BOG condenser.

When a vessel is not unloading, the in-tank column-mounted LNG pumps would circulate LNG through a small diameter circulation line to the pier and back through the unloading line and to the sendout area in order to keep these piping systems cold. In this operating mode, BOG would be continuously generated in the tank due to the heat leak into the system piping, from heat leak through the insulated tank walls, and from the heat added by the pump. Under these operating conditions, the BOG would be compressed by the BOG compressors and condensed in the BOG condenser.

LNG would be pumped out of the LNG storage tank via in-tank, column mounted low pressure LNG sendout pumps. The LNG pressure is increased to pipeline sendout pressure by high pressure LNG pumps before being vaporized into natural gas. Natural gas sendout would be routed through Downeast's sendout pipeline to the M&NE pipeline system at the Baileyville Compressor Station for delivery to end users.

Downeast would operate and maintain its facilities in compliance with 49 CFR 193, 33 CFR 127, NFPA 59A, and other applicable federal and state regulations. In accordance with 49 CFR 193.2503 and 193.2605 and Sections 11.3.1 and 11.5.2 of NFPA 59A, Downeast is required to prepare and submit manuals that address specific procedures for the safe operation and maintenance of the LNG storage and processing facilities. These manuals would address startup, shutdown, cool-down, purging, and other routine operation, maintenance, and monitoring procedures. In accordance with 33 CFR 127.305, Downeast would also prepare an operation manual that addresses specific procedures for the safe operation of the vessel unloading facilities. These manuals would include training requirements and programs for operation and maintenance personnel.

### 2.6.2 Pipeline and Associated Aboveground Facilities

Downeast would operate and maintain the proposed pipeline and associated aboveground facilities in accordance with the applicable safety standards established by the DOT Minimum Federal Safety Standards as specified in 49 CFR 192 and in accordance with the NGA. The pipeline would be patrolled from the air and/or ground on a periodic basis. This patrol would provide information on possible leaks, encroachment onto the right-of-way, third-party construction activity near the pipeline, erosion, exposed pipe, or population density changes in the vicinity of the pipeline. Operation would also include monitoring of cathodic protection units (installed for corrosion control) along the pipeline to ensure proper functioning.

Maintenance activities would include regularly scheduled gas leak surveys, and measures necessary to repair any leaks. All fence posts, signs, marker posts, aerial markers, and decals would be painted or replaced as necessary to ensure the pipeline location remains visible from the air and ground. All valves would be periodically inspected and greased. Maintenance would also include periodic seasonal mowing of the permanent right-of-way, and vegetation control around aboveground facilities. Vegetation control within the 50-foot-wide permanent right-of-way would be conducted every three to five years. A 10-foot-wide area directly over the pipeline would be mowed on an annual basis. According to Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*, herbicides and pesticides would not be used in or within 100 feet of a waterbody or wetland. In addition, our regulations at 18 CFR 380.15 prohibit chemical control of vegetation unless authorized by the landowner or land-managing agency. If chemical use is authorized, our regulations require they be approved by EPA for such use and used in conformance with all applicable regulations.

## 2.7 SAFETY CONTROLS

### 2.7.1 LNG Terminal Facilities

The LNG terminal facilities would be sited, designed, constructed, operated, and maintained in compliance with federal safety standards. Federal siting and design requirements for LNG terminal facilities are summarized in table 2.7.1-1.

#### 2.7.1.1 Spill Containment

The LNG storage tanks that would be installed at the Downeast LNG terminal would be a full containment tank with a primary inner container and a secondary outer container. The tanks would be designed with a self-supporting inner container. The secondary container would be capable of independently containing the LNG. The primary container would contain the LNG under normal operating conditions. The secondary container would be capable of containing 110 percent of the inner container capacity and of controlling vapors resulting from the product leakage from the inner container.

In addition to the full containment storage tanks, three LNG containment basins in the process, vaporizer, and LNG transfer area would be located at the LNG terminal site. Each LNG spill containment basin would be an insulated concrete design. The containment basins would be designed to hold a volume equal to a 10-minute spill. In accordance with Section 2.2.2.7 of NFPA 59A, the containment basins would include automatically activated sump pumps to clear rainwater from the spill containment basins. Water removed from the spill containment basins would be pumped to the stormwater discharge system. The sump pumps would be equipped with thermal interlocks to prevent LNG from being pumped into the drainage systems.

TABLE 2.7.1-1

**Federal Siting and Design Requirements for LNG Facilities**

| Requirement | Description |
|---|---|
| **Thermal Radiation Protection** (49 CFR 193.2057 and Section 2.2.3.2 of NFPA 59A) | This requirement is designed to ensure that certain public land uses and structures outside the LNG facility boundaries are protected in the event of an LNG fire. |
| **Flammable Vapor-Gas Dispersion Protection** (49 CFR 193.2059 and Sections 2.2.3.3 and 2.2.3.4 of NFPA 59A) | This requirement is designed to prevent a flammable vapor cloud associated with an LNG spill from reaching a property line of a property suitable for building. |
| **Seismic Design** (49 CFR 193.2101, and NFPA 59A) | This requirement outlines the necessary site specific seismic hazard study and specifies that critical safety-related components of the facility must be designed to survive earthquake ground motions estimated to have a 1 to 2 percent probability of occurring within a 50-year period. |
| **Wind Forces** (49 CFR 193.2067) | This requirement specifies that all facilities be designed to withstand sustained wind forces of not less than 150 miles per hour without the loss of structural integrity. |
| **Impounded Liquid** (Section 2.2.3.8 of NFPA 59A) | This requirement specifies that liquids in spill impoundment basins cannot be closer than 50 feet from a property line of a property suitable for building or a navigable waterway. |
| **Container Spacing** (Section 2.2.4.1 of NFPA 59A) | This requirement specifies that LNG containers with capacities greater than 70,000 gallons must be located a minimum distance of 0.7 times the container diameter from the property line or buildings. |
| **Vaporizer Spacing** (Section 2.2.5.2 of NFPA 59A) | This requirement specifies that integral heated vaporizers must be located at least 100 feet from a property line of a property suitable for building and at least 50 feet from other select structures and equipment. |
| **Process Equipment Spacing** (Section 2.2.6.1 of NFPA 59A) | This requirement specifies that process equipment containing LNG or flammable gases must be located at least 50 feet from sources of ignition, a property line of a property suitable for building, control rooms, offices, shops, and other occupied structures. |
| **Marine Transfer Spacing** (33 CFR 127.105) | This requirement specifies that each LNG unloading flange must be located at least 985 feet from any bridge crossing a navigable waterway. |

### 2.7.1.2 Hazard Detection System

A Hazard Detection and Mitigation System (HDMS) would be installed to continuously monitor and alert the operator of hazardous conditions throughout the terminal from fire, combustible gas leaks, and low temperature LNG spills. The terminal would have a dedicated standalone system for fire, heat, combustible gas, smoke or combustion product, and low temperature LNG spill monitoring. Fire and gas detection and protection of offices and other buildings would be networked. These would provide common alarms and status information to the HDMS. An independent Safety Instrumentation System (SIS) would also be installed.

HDMS monitoring capability would be provided via graphic displays located in the MCR and the JCR. The terminal would be controlled primarily from the MCR which would be the primary operator interface and monitoring center for the terminal. The JCR would be the control center for unloading operations and would be located on the unloading platform and manned during unloading operations. Both the MCR and the JCR would be equipped to activate the emergency shutdown (ESD) system for the terminal. The MCR operations personnel would also be able to monitor critical alarms and process variables and would be able to manually shut down the unloading operations.

#### 2.7.1.3 Fire Protection System

A firefighting system including fixed and portable firewater and chemical extinguishers and high expansion foam systems would be designed for the facility. The main components of the fire protection system at the LNG terminal include:

- a 360,000-gallon firewater storage tank based on a two-hour sustained flow rate, as required by NFPA 59A. The firewater storage tank would receive water recovered from the SCVs;
- electric and diesel fire pumps located onshore that would draw water from the firewater tank. Each pump would be designed to provide 3,000 gallons at 100 psig;
- single jockey pump to maintain system pressure in the firewater system;
- an LNG storage tank deluge system would be installed to protect storage tanks that are exposed to the heat from fire involving an adjacent tank. The deluge system would draw water from the Passamaquoddy Bay;
- emergency back-up diesel fire pumps that would draw water from the Passamaquoddy Bay. These pumps would be capable of supplying water directly to the pier, the LNG storage tank deluge system, and to the firewater tank to provide emergency makeup water for the firewater system; and
- dry chemical systems consisting of total flooding systems, local application (either fixed nozzle and/or hose line systems), and/or portable extinguishers (handheld and wheeled).

**Nitrogen Snuffing System**

Nitrogen snuffing would be provided at the LNG terminal vent and cold tip vent and would be designed to inject sufficient nitrogen within the vent to maintain oxygen levels below the flammability limits of methane.

**High Expansion Foam System**

Downeast would install a high expansion foam system for the LNG terminal facility. The high expansion foam system would be designed and installed in accordance with NFPA 11A and would be located at each LNG spill containment basin to control ignited or unignited LNG spills.

**Vent Systems**

The terminal would be designed to minimize fugitive emissions with no venting during normal operations using a closed vent drain system. All LNG and natural gas relief valves (excluding LNG storage tank, fuel gas drum and LNG vaporizer relief valves) are vented to a closed vent system that is common with the LNG storage tank vapor spaces. In case of excess relief system pressure, the vent pressure control valve would dump gas to the vent stack. A continuous nitrogen gas sweep would be incorporated downstream of the control valve to ensure proper purging of the vent stack.

**Emergency Shutdown System**

The terminal would have an ESD system with shutdown and control devices designed to maintain safe operating conditions. The ESD system would be used for major incidents and would result in either total plant shutdown, shutdown of vessel unloading, shutdown of the sendout system, and/or shutdown of individual pieces of equipment depending on the type of incident. Two levels of shutdown would be configured for the LNG terminal:

- ESD-1 Shutdown of unloading operations and isolation of the pier and activation of the emergency release couplings on each of the LNG unloading arms and the vapor return arm.
- ESD-2 Shutdown of LNG/NG sendout operations, including ESD-1. This action would isolate the terminal from the natural gas sendout pipeline and from any LNG vessel that would be berthed at the unloading platform.

The MCR and JCR would be equipped with push buttons that activate the ESD system.

## 2.7.2 Pipeline and Associated Aboveground Facilities

### 2.7.2.1 Corrosion Protection and Detection Systems

During construction of the proposed facilities, Downeast would install a cathodic protection system to prevent or minimize corrosion of the buried pipeline and aboveground facilities. The cathodic protection system impresses a low-voltage current on the pipeline to offset natural soil and groundwater corrosion potential. The condition of the pipe coating and the effectiveness of the cathodic protection system would be monitored during regularly scheduled cathodic protection surveys in accordance with federal standards and regulations. Cathodic protection surveys usually require walking the pipeline right-of-way with monitoring instruments. Repairs to the pipe, the pipe coating, or the cathodic protection system would be made as appropriate.

Downeast would also install a Supervisory Control and Data Acquisition (SCADA) system in the operations control center to provide for pipeline control and monitoring at all times. If system pressures fall outside a pre-determined range, an alarm would be activated at the operations center. A real time leak detection system would also be provided for the pipeline.

### 2.7.2.2 Emergency Response Procedures

The proposed pipeline and aboveground facilities must be designed, constructed, operated, and maintained in accordance with the DOT Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. Part 192 specifies material selection and qualification; minimum design requirements; and protection from internal, external, and atmospheric corrosion. Part 192 also prescribes the minimum standards for operating and maintaining pipeline facilities, including the requirement to establish a written plan governing these activities. Under Section 192.615, each pipeline operator must also establish an emergency plan that includes procedures to minimize the hazards in a natural gas pipeline emergency. Key elements of the plan include procedures for:

- receiving, identifying, and classifying emergency events, gas leakage, fires, explosions, and natural disasters;
- establishing and maintaining communications with local fire, police, and public officials, and coordinating emergency response;
- making personnel, equipment, tools, and materials available at the scene of an emergency;
- protecting people first and then property, and making them safe from actual or potential hazards; and
- emergency shutdown of system and safe restoration of service.

Part 192 also requires that each operator must establish and maintain a liaison with appropriate fire, police, and public officials to learn the resources and responsibilities of each organization that may respond to a natural gas pipeline emergency, and to coordinate mutual assistance. The operator must also establish a continuing education program to enable customers, the public, government officials, and those engaged in excavation activities to recognize a gas pipeline emergency and report it to appropriate public officials.

## 2.8 FUTURE PLANS AND ABANDONMENT

Downeast has not indicated that it has plans to expand the facility beyond two 160,000 $m^3$ storage tanks with a nominal sendout capacity of 500 MMcfd with a peak capacity of 625 MMcfd. Downeast currently has no plans for future expansion or abandonment of the proposed terminal or pipeline facilities. Downeast does not foresee abandonment of the terminal facility prior to the expiration of its design life (25+ years) or beyond, provided that terminal components are properly maintained and operated. If abandonment were to occur, Downeast has committed to the Town of Robbinston to restore the property parcel to a non-industrial condition by the removal of terminal components and land restoration actions. This commitment would be insured by a reclamation bond or similar financial guarantee. Should the facilities be expanded or abandoned, a FERC authorization or Certificate and the associated environmental and non-environmental analysis would be required. In addition, the expansion or abandonment would be subject to appropriate federal, state, and local regulations in effect at that time.

## 2.9 NONJURISDICTIONAL FACILITIES

Electrical power to the facility would be supplied by EMEC with a direct tie-in to the property site. EMEC would install a new electric transmission line from their existing switchyard in Milltown to a new substation that would be located across U.S. Route 1 (on the west side of Route 1) from the terminal facility in Robbinston. The proposed location of the new electric transmission line and substation is shown on figures in Appendix I. Both the electric transmission line and the substation would be dedicated to service the Downeast LNG terminal site; therefore, the potential impacts are associated with the Downeast LNG Project.

The electric transmission line would be approximately 13.7 miles in length and would consist of a 69-kilovolt (kV) line. As described in section 2.2.2.1, Downeast anticipates that approximately 11.4 miles of the transmission line would be adjacent to the Downeast sendout pipeline from MP 0.2 to MP 11.6. The remaining 2.3 miles of the electric transmission line route has not been finalized, but has been preliminarily sited to run northwest from the sendout pipeline to a point of origin in the town of Calais (see Appendix I-1).

The substation would be located in a previously disturbed area, on private property that the owner has agreed to sell for the substation. Most of the construction activity is expected to occur within the substation area footprint, which is 0.25 acre, and the access driveway. The acreage of temporary impact due to construction activity is expected to be marginal and immediately adjacent to the substation area. The Downeast LNG terminal would receive power from the substation via a direct electrical feed through a belowground conduit that would pass under U.S. Route 1 and tie-in with the facility at the utility building.

The transmission line would be an intrastate extension of the EMEC electrical distribution system. EMEC would construct, own, operate, and maintain the transmission line and the substation. There are no FERC-required permits or approvals for the transmission line or the substation. Both facilities are subject to the state review process under the jurisdiction of the Maine Public Utilities Commission (Maine PUC). Permits and approvals for these nonjurisdictional facilities would be obtained by EMEC as necessary. Because Downeast would not require electrical service at the project site until after a FERC decision on the LNG project, Downeast has indicated that EMEC has not yet applied for the required environmental permits or approvals for the electrical facilities.

### 2.9.1 Summary of Environmental Impacts

Information filed by Downeast concerning the proposed sendout pipeline project, as well as data compiled by review of United States Geological Survey (USGS) topographic maps and National Wetlands Inventory (NWI) maps, has been used in the following sections to provide a summary of potential environmental impacts of the planned EMEC nonjurisdictional facilities.

#### 2.9.1.1 Water Resources

A total of six waterbodies would be crossed by the electric transmission line from MP 0.2 to MP 11.6. Of these, three would be minor crossings (less than 10 feet in width), and three intermediate (between 10 and 100 feet wide). A detailed description of these waterbodies and others crossed by the Downeast sendout pipeline can be found in section 4.3.2.2. No waterbodies would be crossed by the 2.3 miles of transmission line not collocated with the sendout pipeline (from point of origin in the town of Calais to sendout pipeline MP 11.6).

Activities that could affect surface waters include clearing, construction, and right-of-way maintenance. These activities could result in increased turbidity and sedimentation from rainwater runoff. It is expected that impacts from the crossing of waterbodies by the overhead electric transmission line would be minimal.

#### 2.9.1.2 Vegetation

**Wetlands**

The extent of impact on wetlands crossed by the electric transmission line would be dependent on the type of wetland affected, the existing quality of the wetland, the time of year, and the construction methods.

As detailed in section 4.4.1.3, forested wetlands along the electric transmission line route collocated with the sendout pipeline right-of-way are typically dominated by needle-leaved evergreen trees, balsam fir, red spruce, northern white cedar, and larch, with subdominant broad-leaved deciduous hardwoods, paper birch, red maple, and quaking aspen. Characteristic understory vegetation includes beaked hazelnut, mountain holly, cinnamon fern, evergreen wood fern, swamp dewberry, and *Sphagnum* moss. Scrub-shrub wetlands are often dominated by meadowsweet, speckled alder, and steeplebush and have herbaceous vegetation that includes sensitive fern, pointed broom sedge, and rattlesnake mannagrass. Emergent wetlands are characterized by rushes, sedges, and broad-leaved cat-tail.

Ten vernal pools have been identified within the electric transmission line route collocated with the sendout pipeline right-of-way, five of which are classified as SVPs. Table 4.4.1.3-1 summarizes locations and general description of vernal pools located within the sendout pipeline corridor. The potential impacts on wetlands and vernal pools would depend on the exact location of the electric transmission towers/poles, proposed construction techniques, and mitigation measures. It is anticipated that EMEC would need to take steps to avoid or minimize impacts on wetlands and SVP habitats.

Preliminary reviews of USGS topographic maps and NWI maps indicate that no wetlands would be crossed by the final 2.3 miles of the electric transmission line route. However, because the location of this route has not been finalized and no survey of the area has been conducted, the existence of wetlands and vernal pools cannot be verified. EMEC would consult with the Maine DEP to identify steps needed to avoid or minimize impacts on both wetlands and vernal pools.

**Forests**

The electric transmission line route is predominantly covered by mature forest habitat characterized as spruce-fir, spruce-northern hardwoods, and white-pine mixed hardwoods (Gawler and Cutko 2004). Of these forest types, the spruce fir forest is the most prevalent. Other vegetation communities found along the route include early successional forests and maintained open areas such as open fields, residential, and agricultural land. A detailed description of the forest environment crossed by the Downeast sendout pipeline route can be found in section 4.4.2.3. While the remaining 2.3 miles of the electric transmission line route have not yet been surveyed, it is expected that the forest composition would be similar to that of the proposed sendout pipeline route.

### 2.9.1.3 Threatened and Endangered Species

**State-Listed and Other Special Status Species**

<u>Bald Eagle</u>

Downeast reviewed information from Maine Department of Inland Fisheries and Wildlife (Maine DIFW) that identified the presence of several historic and active bald eagle nests in proximity to the proposed sendout pipeline (see section 4.6.1.2 for details on the bald eagle and section 4.6.2.3 for details on bald eagle mitigation in the sendout pipeline corridor). In all, 1.7 acres (area calculated using a radius of 0.25 mile from nest locations) of inactive nesting habitat were identified along the proposed sendout pipeline, which would be affected by the construction of the EMEC electric transmission line adjacent to the sendout pipeline corridor.

The presence or absence of bald eagles is unknown for the remaining 2.3 miles of electric transmission line that would not be adjacent to the sendout pipeline right-of-way. EMEC would consult with Maine DIFW to determine if active or historic bald eagle nesting habitat exists in the area.

#### 2.9.1.4 Land Use

Most of the land that would be affected along the electric transmission line (see section 4.7.1 for land use details) would be forest land. Other land uses affected along the transmission line would include wetland areas, developed land, agricultural land, grassland/herbaceous land, and unconsolidated shore. The remaining 2.3 miles of electric transmission line not adjacent to the sendout pipeline corridor is expected to be predominantly forest land and possibly some developed land near the town of Calais.

Two residences are approximately 50 feet from the Downeast sendout pipeline construction right-of-way at MP 0.63 and MP 0.91. It is likely that the remaining 2.3 miles of electric transmission line that would not be adjacent to the sendout pipeline corridor would impact residential structures only near the point of origin in the town of Calais. Once the electric transmission line route is finalized, EMEC would negotiate with the landowners to obtain an easement in order to construct and operate the transmission line.

#### 2.9.1.5 Cultural Resources

From MP 0.2 to MP 11.6, there are no recorded archeological sites that are listed in or potentially eligible for listing in the NRHP. Two areas that are yet to be tested, pending permission of landowners, have the potential to contain archeological resources that may be eligible for listing in the NRHP. We do not currently have information about previously recorded archeological sites in areas of the EMEC transmission line that are not adjacent to the Downeast sendout pipeline.

There are no standing structures that may be eligible for listing in the NRHP that have been recorded within the vicinity of MP 6 to MP 11.6. A number of standing structures that are style-dated as 50 years old or older have been recorded near MPs 1, 2, and 5. Visual impact on structures that are potentially eligible for listing in the NRHP may result from construction of the transmission line. The potential impacts would need to be assessed once a route is finalized and details of pole material, height, and interval are determined. We do not have information about recorded structures that may be eligible for listing in the NRHP that are located in areas not aligned with the Downeast sendout pipeline and that may be affected by the transmission line.

### 2.9.2 Conclusion

Under NEPA, the Commission has the responsibility to review infrastructure facilities that are associated with, and a necessary part of, a jurisdictional project. We have summarized the environmental impacts of these nonjurisdictional facilities above. EMEC would obtain the necessary permits and authorizations from the Maine PUC and other relevant agencies prior to construction of these facilities.

# 3.0 ALTERNATIVES

In accordance with NEPA and FERC policy, we have evaluated a range of alternatives to the Downeast LNG Project, as well as alternatives for design and construction of the project. The purpose of this evaluation was to determine whether or not there are reasonable alternatives that would result in less environmental impact than the project as proposed. The proposed action before the FERC is to consider issuing to Downeast a Section 3 authorization for an LNG import facility and a Section 7 Certificate for a new natural gas pipeline.

The Commission has three possible courses of action in processing an application for a project such as that proposed by Downeast. The Commission may: (1) authorize the proposal with or without conditions; (2) deny the proposal; or (3) postpone action pending further study. Alternatives for the FERC action that are addressed in this section include the no action or postponed action alternatives, alternative energy sources, system alternatives, alternative LNG terminal concepts and sites, onshore facility alternatives, alternative pipeline routes, pipeline route variations, and alternative LNG vaporization methods. We identified potential alternatives based on public comments and input from federal, state, and local regulatory agencies, and our own independent research.

Alternatives were evaluated against the stated purpose and need of the project, as described in section 1.1 of this EIS. The purpose of the project is to establish an LNG marine terminal at an acceptable port location in New England capable of receiving imported LNG from LNG vessels, and storing and regasifying the LNG at an average sendout rate of 500 MMcfd. The terminal would provide an additional supply source of natural gas to meet increasing demand in the New England region.

We established several key criteria to evaluate the potential alternatives identified. Each alternative was evaluated in consideration of whether or not it would:

- be technically and economically feasible and practical;
- offer significant environmental advantage over the proposed project or its components; and
- meet the objectives of the proposed project, as described above.

With respect to the first criterion, it is important to recognize that not all conceivable alternatives are technically and economically feasible and practical. For example, some alternatives may not be feasible because the technology may not be available at the time or it may not be possible to implement the alternative due to costs, technological difficulties, or logistics. It is also important to consider the environmental advantages and disadvantages of the proposed action and to focus the analysis on alternatives that may reduce impacts. Further, because the total proposed LNG project would consist of individual components (such as the LNG terminal and the sendout pipeline), all of these components must be present and must function together for the alternative to be considered feasible.

Information used to evaluate alternatives to the proposed project included published studies, comments and suggestions from regulatory agencies, analyses prepared for similar projects, comments from the public, and data and analyses provided by Downeast in its application.

Each alternative was considered until it was clear that the alternative was not reasonable or that the alternative would result in environmental impacts that would be greater than those of the proposed project, as described in section 4.0 of this EIS, and that could not be readily mitigated. This assessment includes the consideration of using existing or proposed LNG projects and siting the project in a different area.

The evaluation of alternatives is presented in the following sections:

- No Action or Postponed Action Alternatives (section 3.1)
- Alternative Energy Sources (section 3.2)
- System Alternatives (section 3.3)
- LNG Terminal Site Alternatives (section 3.4)
- Marine Facility Alternatives (section 3.5)
- LNG Vaporization Alternatives (section 3.6)
- LNG Vessel Design Alternatives (section 3.7)
- Pipeline Location Alternatives (section 3.8)

A regional siting plan has been advocated as a more desirable approach to siting LNG facilities. If a regional siting study is completed during our assessment of the proposed Downeast LNG Project, the Commission may take the conclusions into consideration. However, to date, the Commission has declined to substitute its judgment for that of the market. The Commission's policy prohibiting subsidization of new construction by existing customers works to ensure that an authorized project would not be constructed without adequate support from the market. Further, the Commission policy of authorizing only those projects where adverse impacts have been minimized to the extent possible and potential benefits outweigh any residual impacts, serves to adequately protect the public interest when any authorized project is constructed. Furthermore, Section 313 of the Energy Policy Act of 2005 directs FERC to establish a schedule for the regulatory review that ensures "expeditious completion" of NGA Section 3 and 7 proceedings. Our NEPA scoping process has provided input from the public and regionally based federal, state, and local agencies. This input has been fully considered in the following alternatives. In addition, as part of the planning process for its proposed project, Downeast conducted a siting study that included coastal regions of northern New England, and we have incorporated the results of that study into this EIS. Ultimately, FERC will continue to seek better ways to balance national, regional, state, and local concerns in reviewing LNG import facilities.

## 3.1 NO ACTION OR POSTPONED ACTION ALTERNATIVE

As stated in section 1.1, the proposed project would establish an LNG marine terminal in New England capable of receiving imported LNG from LNG vessels, storing, and regasifying the LNG at an average sendout rate of 500 MMcfd. The terminal would provide an additional supply source of natural gas in the New England region (Maine, Massachusetts, New Hampshire, Vermont, Connecticut, and Rhode Island). The proposed storage tanks at the LNG facility would provide an additional 6.6 Bcf of gas storage capacity in the region. If the Commission denies the proposal (the no action alternative), the short- and long-term environmental impacts identified in this EIS would not occur. If the Commission postpones action on the application, the environmental impacts would be delayed; or if the applicant decided not to pursue the project, the impacts would not occur at all. However, if the Commission selects the no action alternative, Downeast would not be able to provide additional natural gas supplies in order to help meet the increasing natural gas demand in the New England region.

It is purely speculative to predict the resulting effects and actions that could be taken by other suppliers or users of natural gas in the region as well as any associated direct and indirect environmental impacts. However, LNG imports to the New England region are projected to continue through 2035 (EIA 2012). Downeast has stated that natural gas consumers in New England face a future of high natural gas prices and increased risk of supply disruption unless additional sources of natural gas, such as the proposed project, become available.

**No Action or Postponed Action Conclusions**

In addition to the objectives of the proposed project not being met as noted above, if the no action or postponed action alternative is adopted by the Commission, there are two likely outcomes: (1) negative environmental (i.e., increased air emissions and disposal of spent fuel and ash) and economic impacts associated with more limited supplies of natural gas; and/or (2) the development of other natural gas infrastructure projects (i.e., construction of additional pipelines and LNG import terminals) that meet some or all of the project objectives identified by Downeast. For these reasons, we believe that the no action or postponed action alternative is not a reasonable alternative.

## 3.2 ALTERNATIVE ENERGY SOURCES

The adoption of the no action alternative may result in the need for alternative energy sources, or other LNG facilities or additional pipeline capacity to meet the increasing demand for natural gas in New England. This might include constructing or expanding regional pipelines as well as LNG import and storage systems. Any construction or expansion work would result in specific environmental impacts that could be less than, similar to, or greater than those associated with the Downeast LNG Project. We have conducted and included in this EIS an analysis of what appears to be the most reasonable natural gas and LNG system alternatives that have the potential to meet the project objectives.

**Conservation, Efficiency, and Renewable Sources of Energy**

Conservation, increased efficiency, and renewable energy practices have been, and will continue to be, important in meeting the future energy needs of New England. Beginning with the energy crisis of the 1970s, numerous aggressive energy conservation programs have been developed in the region. Although energy conservation measures will be important in addressing future energy demands for the region, these measures would reduce energy demand by only a small fraction and would not replace the need for the project.

Numerous renewable energy incentives have been implemented in the New England region, including solar income tax credits, solar access laws, solar rebate programs, property tax exemptions for geothermal heat pumps, net metering, green power marketing, greenhouse gas initiatives, and energy efficiency and renewable portfolio standards. Renewable energy sources, including wind, hydropower, tidal power, municipal solid wastes, wood and other biomass, and solar power are projected to have some role in meeting New England's future energy needs. The renewable share of total energy use is projected to grow from 9 percent in 2011 to 13 percent in 2040, while natural gas consumption is projected to grow by about 0.6 percent per year from

2011 to 2040 (EIA 2013). Therefore, while renewable energies such as hydroelectric, wind, or solar, are projected to increase, they will not replace the demand for natural gas.

A 2003 report by the American Council for an Energy-Efficient Economy (ACEEE) analyzed projected energy demands in the Northeast. The ACEEE reviewed the national and regional relationship between natural gas price effects of energy efficiency and renewable energy practices and policies (Elliott et al. 2003). The report found that increased installation of renewable energy generation could affect natural gas price and availability. The report concluded that energy efficiency and renewable energy measures could result in a reduction in natural gas consumption in the northeastern states. However, the study also recognized that energy efficiency and renewable energy are not the only policy solutions required to address the future natural gas needs of the United States and that additional sources of natural gas will be required either from domestic sources or through the importation of gas in the form of LNG. The EIA projects that natural gas consumption will grow by about 0.6 percent per year through 2040 (EIA 2013). Furthermore, renewable sources of energy would have project- and site-specific environmental issues such as the disposal of toxic materials, alterations to hydrological/biological systems, and visual impacts. Alternative energy sources could reduce some of the environmental impacts associated with the proposed project but could not individually or cumulatively meet the future energy needs of the New England region.

We received comments during the scoping period regarding impact of the proposed project on in-stream tidal power projects in the Eastport/Lubec area. Potential impact on these renewable energy projects is addressed in section 4.7.3.1 Land Use.

**Nuclear Power Energy**

Energy from nuclear power is expected to grow at an annual rate of 0.5 percent in the United States and 1.6 percent in New England over the next 20 years. However, while important to the overall energy mix, nuclear power is projected to be only 8 percent of total energy consumption in the United States and 15 percent of total energy consumption in New England in 2030, compared to natural gas, which is projected to be 22 percent of total energy consumption in both the United States and New England in 2030. The EIA concludes that nuclear power energy is not a commercially viable substitute able to replace or significantly offset the demand for natural gas over the next 20 years (EIA 2009). Furthermore, nuclear power energy involves significant environmental issues such as the disposal of toxic materials (spent fuel), alterations to hydrological/biological systems, and other concerns.

**Energy from Other Fossil Fuels**

EIA projects that coal consumption will increase at an average rate of less than 0.1 percent per year and petroleum consumption will fall slightly through 2035 (EIA 2012), while natural gas consumption will increase by about 0.6 percent annually (EIA 2013). Further, natural gas is the cleanest burning of the fossil fuels, and reliance on coal or oil to fuel power generation for the region may result in an increased output of air pollutants such as nitrogen oxides ($NO_x$), sulfur dioxide ($SO_2$), mercury, and greenhouse gases (EIA 2009). Given there are emissions associated with producing, processing, transmitting, and distributing natural gas and other fossil fuels, it is difficult to accurately quantify the impact of an LNG import project on air quality. However, credible estimates of air emissions can be developed based on reasonable assumptions regarding burning natural gas delivered by the project compared to burning fossil fuels that would likely be utilized if the gas from the project was not available. Table 3.2-1 lists the emissions that would result from the Downeast LNG Project assuming it provides a baseload rate of about 0.5 Bcfd of natural gas to the market and the corresponding emissions that would result if an equivalent amount of energy were generated using coal or fuel oil in lieu of natural gas. It is clear from the table that the use of either fuel oil or coal would increase emissions significantly. Additionally, to comply with current air emission regulations, emission control technologies could be required that could limit the economic viability of any new oil- or coal-fired facility.

TABLE 3.2-1

**Comparison of Air Emissions from Burning Fossil Fuels a/**

| Fossil Fuel | $SO_2$ (tpy) | $NO_x$ (tpy) | $PM_{10}$ (tpy) | $CO_2$ (tpy) | C (tpy) |
|---|---|---|---|---|---|
| Natural Gas | 55 | 8,277 | 662 | 9,166,666 | 2,500,000 |
| Fuel Oil | 43,320 | 16,556 | 938 | 13,291,666 | 3,625,000 |
| Coal | 115,890 | 57,946 | 2,566 | 17,416,666 | 4,750,000 |

a/ The emissions generated by coal, fuel oil, and natural gas were estimated using Best Available Control Technology (BACT) analyses identified on the EPA Reasonably Available Control Technology/BACT/Lowest Achievable Emission Rate Clearinghouse for boilers with heat input ratings between 100 and 250 million Btus per hour. The emissions from each fuel source are estimated based on a total annual fuel use of 182,500,000 million Btus per year (0.5 billion cubic feet per day, 365 days per year, 1,000 Btus/cubic foot).

$SO_2$=sulfur dioxide $NO_X$=nitrogen oxides $PM_{10}$=particulate matter $CO_2$=carbon dioxide C=carbon tpy=tons per year

In addition to the increased emissions associated with the burning of coal or fuel oil, each of these fuels would also have to be imported into the project area and stored, similar to the proposed LNG. Use of these fuels would require more truck, barge, and train trips than the distribution of an equivalent amount of energy derived from natural gas distributed by pipeline, which would increase air emissions and traffic congestion. The burning of coal would also require disposal of the resulting ash.

As the demand for natural gas is expected to continue to increase into the future, it is conceivable that this demand could be moderated by the increasing use of other energy sources and/or conservation measures. Because natural gas is the least polluting of the fossil fuels, the increased use of other fossil fuels would result in higher air emissions that can contribute to climate change, acid rain, and smog. The economic, ecological, and human health benefits of reduced air emissions have been well documented. It is also conceivable that increasing energy efficiency and use of renewable sources of energy could reduce the projected future demand for natural gas.

EIA (2008) studies have demonstrated that natural gas consumption in New England increased 0.1 percent between 2003 and 2008, and natural gas consumption in the United States is expected to increase 0.6 percent annually through 2040. We cannot accurately predict whether conservation measures or renewable energy sources would replace or significantly offset potential future demand for natural gas supplies in New England. Therefore, we believe that use of alternative energy sources is not a reasonable alternative to the proposed action.

## 3.3 SYSTEM ALTERNATIVES

System alternatives would make use of other existing or proposed facilities in the region to meet the stated purpose of the proposed project, including LNG terminals, natural gas pipeline systems, and offshore natural gas development. A system alternative would make it unnecessary to construct all or part of the proposed project, although some modifications or additions to the system alternative facilities may be necessary. The purpose of identifying and evaluating system alternatives is to determine whether or not potential environmental impacts associated with construction and operation of the proposed facilities could be avoided or reduced while still meeting the project objectives.

### 3.3.1 Pipeline System Alternatives

As an alternative to constructing a new LNG import terminal, we considered the feasibility of using or expanding existing interstate pipeline transmission systems to provide an equivalent amount of natural gas to the New England region as that proposed by Downeast. Existing interstate pipeline systems with major delivery points in New England that could potentially serve as system alternatives include those owned and operated by M&NE, Portland Natural Gas Transmission System (PNGTS), Algonquin, and Tennessee Gas (see figure 3.3-1).

**M&NE Pipeline System**

The M&NE pipeline system in the United States consists of about 215 miles of 24-inch-diameter pipeline from the Canadian border near Calais, Maine, to Westbrook, Maine; about 101 miles of 30-inch-diameter pipeline jointly owned with PNGTS between Westbrook and Dracut, Massachusetts; and about 24 miles of 30-inch-diameter pipeline from Methuen to Beverly, Massachusetts. The M&NE system interconnects with PNGTS in Westbrook, Maine; with the Tennessee Gas system in Dracut, Massachusetts; and the Algonquin system in Beverly, Massachusetts. The M&NE system receives and transports natural gas from developments in offshore Nova Scotia. Capacity of the United States portion of the M&NE pipeline is about 0.42 Bcfd. On February 15, 2007, the Commission authorized M&NE's Phase IV Project which will increase the M&NE system capacity to 0.83 Bcfd. The Phase IV Project delivers natural gas capacity from the Canaport LNG Project, which is currently in operation in eastern Canada. Construction of the M&NE Phase IV Project was completed and the facilities placed into service in January 2009. A discussion of the Canaport LNG Project as a potential system alternative is included in section 3.3.2.1. On April 16, 2008, we approved M&NE's request to initiate pre-filing for the M&NE Phase V Project (PF08-17-000), which would increase capacity on its system by up to 0.17 Bcfd year-round, plus an additional 0.03 Bcfd capacity during the winter months. The project would provide additional capacity to transport new natural gas supplies from EnCana's Deep Panuke gas field project in Maritimes Canada (see section 3.3.3). However, on March 2, 2009, M&NE informed the FERC that it will not be proceeding with the Phase V Project. It was resolved that the Phase V shipper would not need the proposed M&NE facilities to transport its production to markets in the U.S. Northeast.

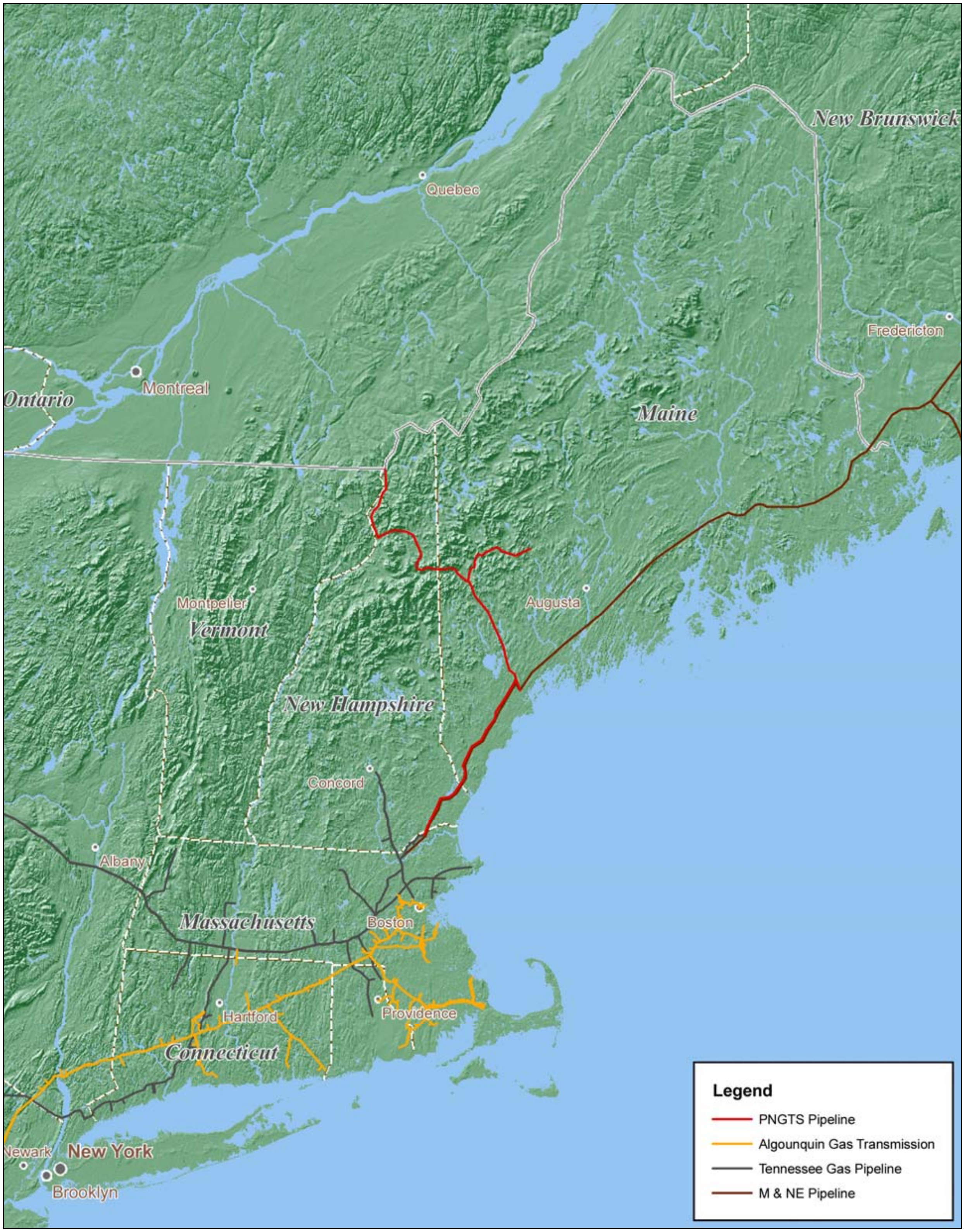



**Figure 3.3-1**
**Downeast LNG Project**
**Existing Interstate Pipeline Systems**
**Considered as Potential System Alternatives**

The M&NE pipeline is the pipeline that Downeast anticipates would transport the additional 0.5 Bcfd of natural gas from the proposed Downeast LNG terminal to existing interconnections in the New England market. As an alternative to the proposed Downeast LNG Project, the M&NE pipeline could be used to transport natural gas received from other source(s) to the New England market. Depending on the source and volume of natural gas, construction of additional gas facilities may be necessary to provide or transport the additional gas. Since the source and volume are not known, it is not possible to evaluate this as an alternative, or if it would provide a significant environmental advantage over the proposed project.

**PNGTS Pipeline System**

The PNGTS pipeline system includes about 144 miles of 24-inch-diameter mainline pipeline from the Canadian border near Pittsburg, New Hampshire to Westbrook, Maine, and about 101 miles of 30-inch-diameter pipeline jointly owned with M&NE between Westbrook and Dracut, Massachusetts. The PNGTS system interconnects with M&NE at Westbrook, Maine and with Tennessee Gas at Dracut. The system is connected to the TransQuebec and Maritimes Pipeline in Canada which receives natural gas primarily from production areas in western Canada and the United States. The system has capacity of about 0.24 Bcfd from Pittsburg to Westbrook, and 0.21 Bcfd from Westbrook to Dracut. Because the PNGTS system is connected to the M&NE system near the primary market area, an expansion of the PNGTS system could provide a conceptual system alternative to the Downeast LNG Project. However, an expansion of the PNGTS system would be required to support the additional 0.5 Bcfd proposed by Downeast. The exact nature of the expansion that would be required and the related environmental impacts is not known, but could include construction of additional pipeline and compression along the existing PNGTS system. Because an expansion of the PNGTS system would have its own set of environmental impacts, we do not believe that expansion of the PNGTS pipeline would be a reasonable system alternative or an environmentally preferable alternative to the Downeast LNG Project. In addition, this system alternative would not meet the Downeast LNG Project objectives of providing a source of imported natural gas and additional natural gas storage facilities.

**Algonquin Pipeline System**

Algonquin, a subsidiary of Spectra Energy, transports about 1.6 Bcfd of natural gas from eastern Pennsylvania to the Boston, Massachusetts area. Algonquin interconnects with the end-point of the M&NE system in Beverly, Massachusetts, and the Tennessee Gas system in Mendon, Massachusetts. To supply an additional 0.5 Bcfd of natural gas to the region, the Algonquin system may require modification and/or expansion. In addition, because Algonquin's operating pressure is only 750 pounds per square inch (psi), the existing 24-inch-diameter pipeline would need to be replaced with larger diameter pipeline along much of the system, or additional loop pipeline added adjacent to the existing pipeline as well as additional compression added to existing or new compressor stations. Because the Algonquin pipeline system is connected to the M&NE system near the primary market area, use of the Algonquin system could provide a conceptual system alternative to the Downeast LNG Project. However, an expansion of the Algonquin system may be necessary to support the additional 0.5 Bcfd proposed by Downeast.

In 2013 Algonquin proposed a system expansion called the Algonquin Incremental Market project (FERC Docket No. PF13-16-000) which would increase capacity on its system by up to about 342,000 dekatherms per day, or approximately 0.3 Bcfd. Algonquin states this project would allow abundant regional natural gas supplies from the Appalachian basin, which would include Marcellus shale, to flow reliably into the Northeast. The project would include construction of approximately 37 miles of new pipeline, additional horsepower at five existing compressor stations, three new meter stations, and modifications to existing meter stations. New construction and modifications would occur along Algonquin's system in New York, Connecticut, Rhode Island, and Massachusetts.

Based on the projected increase in capacity on Algonquin's system (0.3 Bcfd), if this project were constructed it could provide a partial alternative to the additional 0.5 Bcfd of natural gas supply proposed by the Downeast LNG Project. However, this system alternative would not meet the Downeast LNG Project objectives of providing a source of imported natural gas and additional natural gas storage facilities. Downeast has proposed its project in anticipation of a need for additional natural gas volumes in New England, beyond that which would be provided by Algonquin's proposed system expansion. The Commission must evaluate the merits and associated environmental impacts of the proposed Downeast LNG Project. Future market demand could justify construction of the Downeast LNG Project in addition to an expansion of the Algonquin pipeline system.

**Tennessee Gas Pipeline System**

Tennessee Gas, a unit of the El Paso Corporation, serves the New England region through points in New York and Pennsylvania, with end points in southern New Hampshire and eastern Massachusetts, north and south of Boston. The source of natural gas in this system is from various production areas in the Gulf of Mexico as well as Marcellus Shale region in Pennsylvania and Ohio. The Tennessee Gas system interconnects with the joint M&NE/PNGTS pipeline in Dracut, Massachusetts and with the Algonquin system in Mendon, Massachusetts. In November 2012, Tennessee Gas placed a new expansion project in service that increased capacity on its 300 Line system which moves product from the Marcellus Shale region to markets in New England and northern New York. Its Northeast Supply Diversification Project added 250,000 dekatherms per day (about 240 MMcfd), which is about 40 percent of the proposed peak delivery capacity of the Downeast LNG Project. A similar future expansion of the Tennessee Gas system could potentially provide a volume of natural gas to New England that could make up the volume proposed by Downeast. The exact nature of an expansion is not known, however, such an expansion may require significant new pipeline facilities along its system, including through densely developed areas. Because an expansion of the Tennessee Gas system would have its own set of environmental impacts, we do not believe that expansion of the Tennessee Gas system would be a reasonable system alternative or an environmentally preferable alternative to the Downeast LNG Project. In addition, this system alternative would not meet the Downeast LNG Project objectives of providing a source of imported natural gas and additional natural gas storage facilities.

**Conclusions on Pipeline System Alternatives**

Expanding or modifying the existing pipeline systems to be able to deliver the natural gas volumes proposed by Downeast to northern and eastern New England would result in a variety of environmental impacts depending on the project size, length, and design. It is typical for significant pipeline construction projects in the region to result in short- or long-term impacts on water resources, vegetation, wetlands, wildlife habitats, and land use. Substantial expansion or modifications to existing pipeline systems may be required to deliver the gas volumes to the markets proposed by Downeast. In addition to construction-related effects, operation of pipeline compressor stations may also result in permanent noise and air quality impacts.

We expect that new pipelines or proposals to modify existing pipelines will continue to increase the capacity of existing systems delivering natural gas to New England. Nevertheless, these projects could not meet the project objectives of providing access to new natural gas supplies from around the world. Expansion of an existing pipeline system would also not meet the project objective of increasing the supply diversity in the region. Even if a pipeline system alternative was combined with the use of an existing, modified, or proposed LNG facility, the environmental impacts of such an alternative would not provide a clear advantage over the Downeast LNG Project.

### 3.3.2 LNG Terminal System Alternatives

Existing and potential new LNG terminals considered as potential system alternatives to the project are shown in figure 3.3-2. With the exception of the existing operating terminals, all of the potential new LNG terminals considered in our analysis were previously proposed and at various states of approval or construction, but all have since been cancelled or suspended and are no longer actively proposed. LNG terminals included in our analysis are, or would be, located in the New England coastal region or in eastern Canada (FERC 2013a, 2013b; Natural Resources Canada 2011). Because of the close proximity of several proposed LNG import projects in eastern Canada, and because some of these projects would supply natural gas, at least partially, to the northeastern United States, we have included these projects in our alternatives analysis. Our analysis did not consider existing or proposed LNG terminals in other parts of North America, such as the Mid-Atlantic, Southeast, and Gulf Coast regions, because these facilities serve different markets, and use of those facilities would require substantial new infrastructure development to transport gas to New England. Further, we did not consider the proposed KeySpan LNG Terminal Project in Providence, Rhode Island, because in June 2005 the Commission declined to authorize this project. In August 2005, KeySpan filed an appeal of that denial. In January 2006, FERC upheld its denial, and Keyspan withdrew its appeal and suspended further work on the project in 2007. Table 3.3.2-1 lists the LNG terminals considered in our analysis and their relevant characteristics.

#### 3.3.2.1 Existing LNG Terminals in New England and Eastern Canada

**Distrigas LNG Terminal**

The Distrigas LNG facility is owned by GDF Suez. The facility is about 250 miles from the proposed Downeast LNG Project on a 24-acre site on the Mystic River in Boston Harbor that is surrounded by industrial development. In service since 1971, the Distrigas facility is the oldest LNG import terminal in the United States. In 2000 and 2001, the FERC authorized installation of a vapor recovery system to recover flash gas during vessel unloading, replacement of all vaporizers to be compatible with a new thermal transfer system and a new adjacent power plant, and the installation of additional vaporizers and pumps to provide natural gas service to an electric power generation plant. Installation of these new facilities is complete.

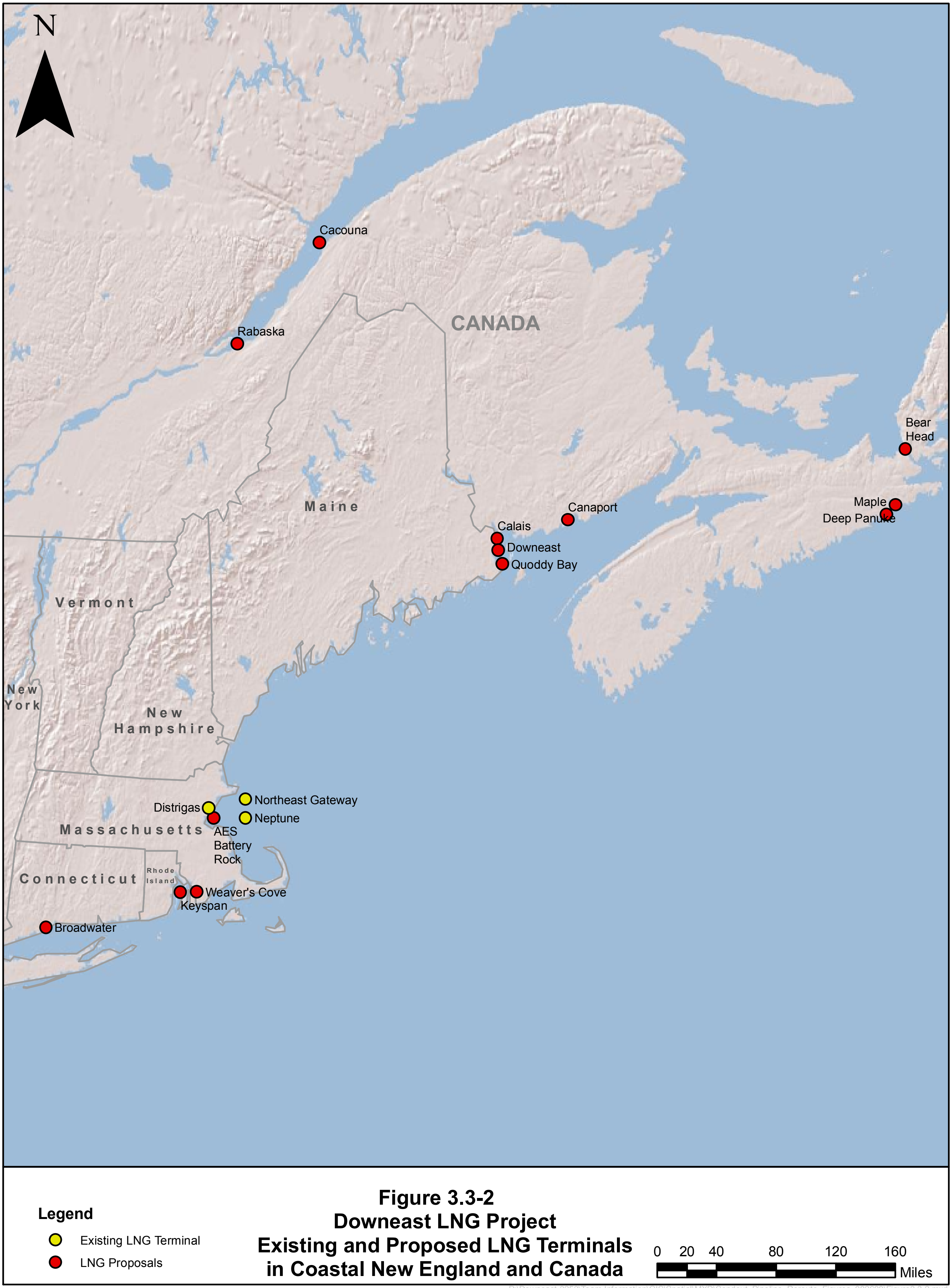



**Figure 3.3-2**
**Downeast LNG Project**
**Existing and Proposed LNG Terminals**
**in Coastal New England and Canada**

TABLE 3.3.2-1

**Existing and Potential New LNG Terminals Considered as Alternatives**

| Project | Location and Approximate Distance from Downeast | Daily Sendout Capacity (Bcfd) | Target Market | Facility Type | Status |
|---|---|---|---|---|---|
| **Existing In-Service Projects** | | | | | |
| Distrigas LNG | Boston, Massachusetts (250 miles) | 0.7 | New England | Onshore | Operating |
| Northeast Gateway Energy Bridge | Offshore Gloucester, Massachusetts (250 miles) | 0.8 | New England | Offshore, shuttle regasification vessel (SRV) a/ | Operating as of May 2008. |
| Neptune LNG Deepwater Port | Offshore Gloucester, Massachusetts (250 miles) | 0.4 | New England | Offshore, SRV a/ | Operating as of May 2010. |
| Canaport LNG | St. John, New Brunswick (60 miles) | 1.0 | New England and eastern Canada | Onshore | Operating as of June 2009. |
| **Potential New Projects (Previously planned but currently suspended or cancelled)** | | | | | |
| Weaver's Cove LNG | Fall River, Massachusetts (300 miles) | 0.8 | New England (southeastern Massachusetts and Rhode Island) | Onshore | Approved by FERC; Filed application for offshore berth alternative in January 2009. Project withdrawn by the proponent in June 2011. |
| Bear Head LNG | Point Tupper, Nova Scotia (290 miles) | 1.0 | New England and eastern Canada | Onshore | Construction began 2004 but suspended/cancelled due to lack of long-term LNG supply. |
| Maple LNG | Goldboro, Nova Scotia (250 miles) | 1.0 (additional 1.0 with expansion) | Eastern Canada | Onshore | Approved by Canadian government. Project withdrawn by the proponent in August 2010. |
| Cacouna Energy | Gros Cacouna, Quebec (230 miles) | 0.5 | Quebec, Ontario, Northeast US | Onshore | Approved by Canadian government; Suspended as of December 2008. Decision to not extend option to lease project site announced in November 2009. |
| Rabaska | Quebec City, Quebec (230 miles) | 0.5 | Quebec, Ontario | Onshore | Approved by Canadian government; Project suspended. |
| Quoddy Bay LNG | Perry, Maine (8 miles) | 2.0 | New England | Onshore | FERC dismissed application via Order issued October 17, 2008 |
| Calais LNG | Calais, Maine (10 miles) | 1.0 | New England | Onshore | FERC dismissed application via Order issued April 2012. |
| Grande-Anse Project | Port of Grande-Anse, Quebec, Canada | 1.0 | Quebec, Ontario | Onshore | Project suspended. |
| AES Battery Rock | Boston, Massachusetts (250 miles) | 0.8 | New England | Onshore | Announced in 2006, cancelled in April 2007. |

a/ Shuttle regasification vessels (SRVs) are marine vessels that transport LNG and have onboard vaporization equipment. Vaporized LNG is transferred from the SRV to a pipeline riser that is attached to an offshore buoy.

The Distrigas facility has two tanks that can store 155,000 $m^3$ of LNG. The facility has an installed vaporization capacity of 1.035 Bcfd; however, due to pipeline capacity, maximum sendout is limited to 0.715 Bcfd. A significant quantity of LNG is loaded onto LNG trucks and delivered to peakshaving facilities throughout New England. The four-bay truck station on the site can fill up to 100 trucks per day. Distrigas signed a deal with its supplier in 2010 that would bring in up to 30 LNG vessels per year to this facility.

The Distrigas facility is dedicated to LNG imported by GDF Suez and is not operated as an open-access import terminal that provides terminalling services to other parties. To provide the same service as proposed by Downeast, Distrigas would need to add another 320,000 $m^3$ of storage and up to about 0.5 Bcfd of vaporization. There is no space on the existing 24-acre site to construct the additional facilities associated with the proposed Downeast LNG Project, nor is there available adjoining property to accommodate these facilities and the associated exclusion zones. Therefore, we believe that expansion of the existing Distrigas LNG import terminal is not a feasible system alternative.

While it does not appear that the existing Distrigas facility could be reasonably expanded to satisfy all of the objectives of the Downeast LNG Project, it is conceivable that the facility could be expanded to provide some additional natural gas sendout capacity. For example, in 2003 the Commission received an application to review the Everett Extension Project. Although this proposal was later withdrawn by the proponents because it was not thought to be economically viable, the Everett Extension Project would allow Distrigas to mitigate some take-away constraints and allow sendout of an additional 0.11 Bcfd of natural gas via a pipeline operated by Algonquin. The project would depend on construction of the Deer Island Lateral, which was approved by the Commission in 2002 but never constructed, and a new lateral pipeline that would extend from the Deer Island Lateral to a connection with Algonquin's existing J-System, which interconnects with the Distrigas LNG facility in Everett, Massachusetts. The facilities required for the project would include reconfiguration of existing vaporization equipment within the existing boundaries of the Distrigas property and new pipeline facilities to be constructed by Algonquin.

The pipeline facilities for the Everett Extension Project would include 12.4 miles of pipeline (including the Deer Island Lateral Pipeline), with 4.2 miles onshore and the other 8.2 miles offshore in Boston Harbor. About 2.4 miles of the offshore pipeline would be installed using HDD techniques and the remaining portion would be installed by dredging, jetting, or plowing. Impacts would include temporary disruption of local roadways and recreational trails, noise during construction, increased turbidity and sedimentation as a result of offshore construction, and direct and indirect impacts on aquatic resources. Because of environmental and permitting constraints, the working conditions in Boston Harbor, and other factors, the Everett Extension Project was not considered economically viable. We are not aware of other ways in which the Distrigas LNG facility could be reasonably expanded to allow additional natural gas sendout or provide more LNG storage. Therefore, we do not believe that an expansion of the Distrigas LNG facility is an economically feasible alternative, nor would it offer significant environmental advantage over the proposed project.

## Northeast Gateway LNG Project

The Northeast Gateway Energy Bridge (Northeast Gateway) Project is an offshore LNG import facility located within Massachusetts Bay, about 13 miles south-southeast of Gloucester, Massachusetts. The Northeast Gateway Project began operation in May 2008, and is capable of mooring specially designed LNG regasification vessels with a capacity of about 138,000 $m^3$. This facility has no LNG storage capability, and is capable of providing a baseload delivery of 0.4 Bcfd and peak deliveries of approximately 0.8 Bcfd through a 16.4-mile-long, 24-inch-diameter submarine pipeline connecting to the Algonquin HubLine Pipeline System.

The Northeast Gateway Project serves the same New England market as proposed for the Downeast LNG Project, and provides about the same baseload delivery and slightly more peak delivery as proposed by Downeast. However, Northeast Gateway does not provide any storage capacity, and therefore does not meet Downeast's objectives of providing natural gas storage facilities. It may be possible that the Northeast Gateway Project could be modified to accept additional LNG vessel deliveries, and increase the baseload delivery to the New England market enough to be considered an alternative to the Downeast LNG Project. Such an expansion would require modification of the existing permits and authorizations, and may require expansion of the existing sendout pipeline or addition of a second pipeline. Therefore, while the Northeast Gateway Project partially meets one of the objectives of the Downeast LNG Project, it does not meet all of the objectives, and we do not believe that the Northeast Gateway Project would serve as a system alternative to the Downeast LNG Project. We have, however, further evaluated the potential for the Northeast Gateway Project in combination with the Neptune LNG Project (discussed below) to be a system alternative to the Downeast LNG Project (see section 3.3.2.2).

## Neptune LNG Project

The Neptune LNG Project is an offshore LNG import facility located within Massachusetts Bay approximately 22 miles northeast of Boston, Massachusetts, and approximately 7.0 miles south-southeast of Gloucester, Massachusetts. The facility is located in federal waters on the Outer Continental Shelf and is designed for mooring specially designed LNG regasification vessels with a capacity of about 140,000 $m^3$. The project includes two separate buoys to allow continual delivery of gas with an average throughput capacity of 0.4 Bcfd and a peak capacity of 0.75 Bcfd. The facility does not have LNG storage capacity. The project connects to the existing Algonquin HubLine Pipeline System. The project became operational in May 2010. However, in May 2012 Neptune LNG requested, and the Maritime Administration approved, a temporary five-year suspension of operations at the facility. During the suspension period the Neptune LNG Project must maintain compliance with the terms, conditions, and requirements of the deepwater port license amendment. Because the suspension of operations is temporary, we continue to consider the Neptune LNG Project as a potential alternative.

The Neptune LNG Project serves the same Boston area market proposed for the Downeast LNG Project, and provides about the same baseload delivery and slightly more peak delivery than proposed by Downeast. However, the Neptune Project does not provide any storage capacity, and would therefore not meet Downeast's objectives of providing natural gas storage facilities. Therefore, while the Neptune LNG Project would partially meet one of the objectives of the Downeast LNG Project, it could not meet all the objectives, and we do not believe that the Neptune LNG Project would serve as a system alternative to the Downeast LNG Project. We have, however, further evaluated the potential for the Neptune LNG Project in combination with the Northeast Gateway Project to be a system alternative to the Downeast LNG Project (see section 3.3.2.2).

**Canaport LNG Project**

The Canaport LNG Project is located at the Irving Canaport facility near St. John, New Brunswick, Canada. The project includes three LNG storage tanks and vaporization to provide a sendout capacity of 1.2 Bcfd. The project began operating in June 2009. Markets for natural gas from the Canaport facility include use of the gas at the existing refinery at Canaport (and possibly a new power plant), sale of gas to local and New Brunswick markets, and supply to potential demand along the existing pipeline corridor. Natural gas from the Canaport LNG Project not consumed in Canada can be transported to the same U.S. markets that the Downeast LNG Project would supply through the same M&NE pipeline system.

A potential alternative to the Downeast LNG Project could be an expansion of the Canaport LNG Project that would provide an additional 320,000 $m^3$ of storage and up to 0.5 Bcfd of vaporization and sendout capacity. While it appears additional land area may be available at the Canaport LNG site for a fourth LNG storage tank and additional vaporization, we have not conducted, nor are we aware that others have conducted, an engineering review to determine if the terminal site could be physically enlarged to provide additional LNG storage and vaporization capacity beyond what is currently approved. An expansion of the LNG storage and sendout capacity would require additional LNG vessel deliveries to the terminal, and possibly an additional ship berth. Expansion of the Canaport LNG Project as an alternative to the Downeast LNG Project could also require additional or expanded pipeline facilities in Canada and the United States to increase take away capacity. The exact nature of such an expansion and any related environmental impacts have not been identified, however such an expansion would likely require construction of a new LNG storage tank and vaporization facilities, additional LNG vessel traffic, and possibly new natural gas pipelines. Therefore, such an alternative would have environmental impacts generally similar in nature than the proposed Downeast LNG Project. Also, it is unclear if the Canaport LNG Project site could support such an expansion. For these reasons, we do not believe that an expansion of the Canaport LNG Project would be an environmentally preferable alternative.

### 3.3.2.2 Combination of Existing Projects

It is possible that some combination of two or more of the existing LNG terminal projects described above, or future expansions of those projects, could provide an equivalent of the proposed delivery of 500 MMcfd of natural gas to the New England market and could serve as an alternative to the proposed Downeast LNG Project. Under such an alternative, the necessary changes or expansions at each project could be incremental, and related environmental impact at each project could also be relatively minor. However, when combined, cumulative impacts from these expansions could be similar or greater than impacts from the proposed project. The total environmental impact of such an alternative would depend on exactly which projects and which components of each project were included or expanded to make up the alternative. The potential alternative of a combined Northeast Gateway LNG and Neptune LNG Projects is discussed below.

### Northeast Gateway LNG and Neptune LNG Projects

We believe a combination of the existing Northeast Gateway Project and Neptune LNG Project merits evaluation as a potential alternative to the proposed Downeast LNG Project. Such a combination would provide a new delivery point of natural gas to New England via an LNG import terminal. The potential for either project alone to serve as an alternative is discussed above.

The Northeast Gateway and Neptune LNG Projects combined would provide a baseload delivery of 0.8 Bcfd and peak deliveries of approximately 1.55 Bcfd, and could therefore meet Downeast's purpose of providing 500 MMcfd (0.5 Bcfd) baseload and up to 625 MMcfd (0.625 Bcfd) peak delivery, of natural gas to the New England market. Neither Northeast Gateway nor Neptune LNG would provide LNG storage; therefore, even a combination of both existing projects would not meet the objective of the Downeast LNG Project of providing 320,000 $m^3$ of storage capacity. However, the ability of the combined projects to provide baseload delivery and peak delivery of 0.3 Bcfd and 0.925 Bcfd, respectively, above that proposed by Downeast, may compensate for the lack of LNG storage capacity. In addition, it is possible that a new storage facility could be constructed to add storage capacity to either existing project. No such facility has been identified or proposed and the potential site and related potential environmental impacts of this conceptual alternative have not been identified.

Environmental impacts of the existing projects have been evaluated and described in their respective EISs, and an alternative of both existing projects combined would not result in additional environmental impacts beyond that described in the respective EISs. A combined Northeast Gateway and Neptune LNG Projects alternative, without LNG storage, would not have land-based impacts, and we believe would have less environmental impact than the proposed Downeast LNG Project. However, Downeast has proposed its project in anticipation of a need for additional natural gas volumes in New England, beyond that which would be provided by Northeast Gateway and Neptune LNG. The Commission must evaluate the merits and associated environmental impacts of the proposed Downeast LNG Project. Despite the current weak economy and resulting short-term decrease in domestic energy consumption, future market demand could justify construction of the Downeast LNG Project, in addition to the existing Northeast Gateway and Neptune LNG Projects.

## 3.3.2.3 Previously Proposed LNG Projects

The LNG projects discussed below are no longer proposed, or have been placed on hold for various reasons. We have included discussion of them as alternatives, in case their status were to change in the future.

### Weaver's Cove LNG Project

In June 2005, the Commission approved the Weaver's Cove LNG Project in Fall River, Massachusetts (Docket No. CP04-36-000). To address environmental and safety concerns raised by various stakeholders, Weaver's Cove proposed an amendment to its proposed project in January 2009 under Docket No. CP04-36-005. The amendment would involve construction of an offshore LNG berth in Mount Hope Bay and cryogenic LNG transfer pipelines that would transport LNG from the offshore berth to the onshore LNG storage tanks at the authorized terminal. Weaver's Cove withdrew its application for the project in June 2011.

As originally proposed, the Weaver's Cove LNG Project would serve specific customers in the Northeast and New England states. As an alternative to Downeast's proposal, it is possible that the Weaver's Cove LNG Project as approved could be expanded to provide the additional storage and sendout capacity proposed by Downeast. To provide the same service as proposed by Downeast, it would be necessary to add another 320,000 $m^3$ of storage and up to 0.5 Bcfd of vaporization. In its application, Weaver's Cove stated that if there is a future demand for natural gas in its market area, the maximum sendout capacity could be increased by an additional 0.2 Bcfd with the addition of heaters and a vaporizer. It is also possible that an additional storage tank could be added, provided adjacent land area could be secured to provide the necessary safety and exclusion zones. While it appears additional land area may be available at the Weaver's Cove site, we have not conducted, nor are we aware that others have conducted, an engineering review to determine if the terminal site could be physically enlarged to provide additional LNG storage and vaporization capacity beyond what is proposed by Weaver's Cove. In addition, an expansion of the LNG storage and sendout capacity would require additional LNG vessel deliveries to the terminal, and possibly an additional ship berth. Construction and expansion of the Weaver's Cove terminal as an alternative to the Downeast LNG Project would also require additional or expanded pipeline facilities to increase take away capacity, the length and location of which is not known. The construction and expansion of the Weaver's Cove LNG Project as an alternative to the Downeast LNG Project would result in its own set of environmental impacts similar to, or potentially greater than, those from the proposed Downeast LNG Project. Furthermore, Weaver's Cove has withdrawn the application for the project and it is uncertain if a revised or similar LNG project would ever be proposed at the Weaver's Cove site. Therefore, we do not consider construction and expansion of the Weaver's Cove LNG Project to be a practical alternative to the Downeast LNG Project.

**Bear Head LNG Project**

Anadarko Petroleum planned to build the Bear Head LNG Project on Cape Breton Island, Nova Scotia. The project would be constructed and operated in two phases, with the first phase providing sendout capacity of 1.0 Bcfd and the second phase increasing sendout capacity to 1.5 Bcfd. Construction began in 2004, however it was halted in May 2006, and on February 6, 2007, Anadarko announced the project will be put on hold because it was unable to obtain long-term LNG supply. The initial proposal included delivery of natural gas from Bear Head LNG to northeast Canada and United States markets, with delivery to the United States via an expansion of the existing M&NE system. To accommodate this supply to the United States (and supply from the Canaport LNG Project, see below), M&NE entered into the FERC Pre-filing Review Process (PF05-17-000) for the Phase IV Expansion Project, initially proposed to include 146 miles of looped 36-inch-diameter pipeline along the existing route and six new compressor stations in Maine and Massachusetts, terminating in Dracut, Massachusetts. In May 2006, in response to the announcement that construction of the Bear Head LNG Project had been discontinued indefinitely, M&NE modified the Phase IV proposal to eliminate a new compressor station and all but 1.7 miles of new pipeline in Maine (Docket No. CP06-335-000). Because the Bear Head LNG Project is now on hold with no immediate plans to continue development, we do not believe it is a feasible system alternative to the Downeast LNG Project. Even if the Bear Head LNG terminal were to become operational, substantial upgrades to the downstream interstate pipeline systems and, potentially, the LNG terminal itself would be required to meet regional market needs. Impacts associated with these upgrades would be equal to, or greater than, those associated with the Downeast LNG Project. Therefore, if the Bear Head LNG Project were to be constructed, we do not believe that an expansion of it would be an environmentally preferable alternative to the Downeast LNG Project.

**Maple LNG Project**

Maple LNG proposed to construct an LNG import terminal in Goldboro, Nova Scotia. The terminal would include LNG storage and regasification facilities, and would be constructed in association with an adjacent petrochemical complex and an electric co-generation facility. As proposed, the project would have a natural gas sendout capacity of 1.0 Bcfd and originally projected an in service date of 2009. The sendout pipeline from the LNG facility would tie into the Canadian portion of the existing M&NE system. An application for the project was filed in January 2005 with the Nova Scotia Department of Environmental Labor. Maple LNG had received Canadian federal and provincial approval, as well as the required permits to construct and operate the terminal and petrochemical facility (Natural Resources Canada 2008). However, plans to develop the project were halted by Maple LNG in April 2010.

Although the project would tie into the M&NE system, Maple LNG had not determined what part of the sendout from the project would be directed to the United States. As planned, much of the natural gas made available from the terminal would be used in the adjacent petrochemical complex and co-generation plant in Canada. Therefore, while the Maple LNG Project as originally proposed could be a partial alternative to the Downeast LNG Project, it would likely only provide a small portion of Downeast's proposed volume of natural gas to New England, if any.

A potential alternative to the Downeast LNG Project could be an expansion of the Maple LNG Project that would provide an additional 320,000 $m^3$ of storage and up to 0.5 Bcfd of vaporization and sendout capacity. While it appears additional land area may be available at the Maple LNG site for additional LNG storage and vaporization, we have not conducted, nor are we aware that others have conducted, an engineering review to determine if the terminal site could be physically enlarged to provide additional LNG storage and vaporization capacity beyond what is currently approved. While the exact nature of such an expansion and any related environmental impacts have not been identified, an expansion of the LNG storage and sendout capacity would likely require additional LNG vessel deliveries to the terminal, and possibly an additional ship berth. Construction and expansion of the Maple LNG Project as an alternative to the Downeast LNG Project may also require additional or expanded pipeline facilities in Canada and the United States to increase take away capacity. Because construction and expansion of the Maple LNG Project would likely require construction of new LNG storage and vaporization facilities, additional LNG vessel traffic, and new natural gas pipelines, such an alternative would be expected to have similar environmental impacts than the proposed Downeast LNG Project. Also, it is unclear if the Maple LNG Project site could support such an expansion. Furthermore, plans to develop the project have been halted by Maple LNG and it is uncertain if a new or revised project would ever be proposed at the site. For these reasons, we do not believe that construction and expansion of the Maple LNG Project would be an environmentally preferable alternative.

## Cacouna Energy LNG Project

TransCanada and Petro-Canada proposed an LNG storage and regasification project on Gros Cacouna Island in the St. Lawrence River near Riviere du Loup, Quebec. The capacity of this facility would be about 0.5 Bcfd and was originally proposed to be in service in 2009. About 150 miles of new pipeline would be constructed to provide necessary sendout capacity. The provinces of Quebec and Ontario would be the primary markets for this project; however, the northeastern United States is also a potential market.

The Cacouna Energy LNG Project could potentially supply a portion of the natural gas to New England that is proposed by the Downeast LNG Project. However, the volume of gas that would be available to the northeastern U.S markets is uncertain, and it is reasonable to assume that most natural gas would be dedicated to markets in Quebec and eastern Ontario. The project was awarded Canadian federal and provincial regulatory approval in June 2007; however, Cacouna Energy announced on December 31, 2008, that it was closing its offices for an indefinite period due to world market LNG supply conditions and other economic factors, stating that conditions do not exist for construction of the terminal at this time. In November 2009, the proponents announced that they would not extend the option to lease the project site, and the project is considered suspended. Therefore, we do not believe that the Cacouna Energy LNG Project would be a practical alternative to the Downeast LNG Project.

## Rabaska LNG Project

The Rabaska LNG Project was proposed in Lévis near Quebec City, Quebec, and included a jetty, a cryogenic pipe, two LNG storage tanks, and regasification equipment. The Rabaska LNG terminal was proposed to connect to the Canadian gas transport network through a 24-inch-diameter pipeline, extending approximately 26 miles from the LNG terminal to the Trans Quebec and Maritimes Pipeline distribution station in Saint-Nicolas. The entire 0.5-Bcfd proposed sendout capacity was designated for markets in Quebec and eastern Ontario, with no capacity designated for the United States. The Rabaska project proponents received Canadian federal and provincial approval, as well as the required permits to construct and operate the facility. In addition, Rabaska signed a Memorandum of Understanding with Russia's Gazprom for LNG supply starting in 2014. However, Rabaska has since halted plans to develop the project (Natural Resources Canada 2011). Given the lack of capacity for U.S. northeast markets, and the fact that Rabaska has suspended plans for the project, we conclude the Rabaska LNG Project is not a viable system alternative to the Downeast LNG Project.

## Grande-Anse Project

Énergie Grande-Anse Inc. had proposed to develop and build in collaboration with the Saguenay Port Authority (SPA) an LNG import terminal in the Port of Grande-Anse, along the Saguenay River in Quebec, Canada. The LNG terminal would include a deep water wharf to be built and operated by the SPA; cryogenic piping and accessories to deliver the LNG to the storage tanks; three storage tanks, each having a capacity of 160,000 $m^3$; and a regasification facility. Énergie Grande-Anse Inc. estimated that approximately 110 LNG vessels per year would transport the LNG along the Saguenay River to the Port of Grande-Anse. As proposed, the facility would have an initial send-out capacity of about 1 Bcfd (Natural Resources Canada 2008). The project began review by the Canadian Environmental Assessment Agency as well as by the Government of Québec under the Quebec Environment Quality Act. However, Énergie Grande-Anse has since suspended plans to develop the project (Natural Resources Canada 2011). As originally proposed, the project's sendout capacity was designated, in order of priority, first for markets in Quebec and Ontario, and last for markets in the Northeast United States. Given the uncertainty of capacity for U.S. northeast markets, and the fact that plans to develop the project have been halted, we conclude the Grande-Anse Project is not a viable system alternative to the Downeast LNG Project.

**Quoddy Bay LNG Project**

On December 15, 2006, Quoddy Bay LNG filed an application with the FERC (Docket No. CP07-35-000) seeking authority to construct and operate a new LNG import terminal and storage facility at Split Rock on the Passamaquoddy Tribe's Pleasant Point Reservation, in the Town of Perry, Maine. In a February 29, 2008 filing, Quoddy Bay indicated possible revisions to the project design pending negotiations with LNG suppliers and investigation into the use of additional mitigation measures. On April 25, 2008, the Commission suspended its review of Quoddy Bay LNG's application since Quoddy Bay LNG was unable to provide any further information regarding possible revisions to the project design, or information required by FERC staff to proceed with its engineering review and preparation of the draft EIS. On October 17, 2008, the Commission dismissed Quoddy Bay's applications. This dismissal was without prejudice to Quoddy Bay filing a new application in the future if Quoddy Bay is able to finalize its design and provide a complete application.

As originally proposed, Quoddy Bay's proposed LNG terminal site would be about 8 miles south of Downeast's proposed site. The Quoddy Bay LNG Project would include two LNG ship berths and associated unloading platforms and pipeline, a submarine cryogenic pipeline, three 160,000 $m^3$ storage tanks, and a 36-mile-long, 36-inch-diameter natural gas sendout pipeline extending from the LNG terminal to the existing M&NE pipeline system at the Baileyville, Maine Compressor Station. The maximum sendout capacity of the Quoddy Bay LNG Project would be about 2.0 Bcfd.

The Quoddy Bay LNG Project would supply more natural gas volume to New England than is proposed by Downeast; therefore, the Quoddy Bay LNG Project as originally proposed could potentially serve as a system alternative to the Downeast LNG Project. However, given that the Quoddy Bay LNG Project application has been dismissed, we do not consider the project as a viable or reasonable system alternative to the proposed project.

**Calais LNG Project**

On May 30, 2008, Calais LNG Project Company LLC (Calais LNG) filed a request with the FERC to initiate the NEPA Pre-filing Process for a proposed LNG import, storage, and regasification terminal near Ford Point on the St. Croix River in the City of Calais, Washington County, Maine. On June 18, 2008, the FERC initiated the NEPA Pre-filing Process for the Calais LNG Project. The project would be about 15 miles upriver from the proposed Downeast LNG terminal and would have two 160,000 $m^3$ LNG storage tanks and a normal sendout capacity of about 1.0 Bcfd and peak sendout capacity of 1.5 Bcfd. The project would connect to the M&NE Pipeline system near the Baileyville Compressor Station with about 20 miles of 36-inch-diameter pipeline, using a pipeline route similar to Downeast's proposed sendout pipeline route beginning at about MP 14. The Commission dismissed the Calais LNG project application in April 2012, and the project is no longer under review. As originally proposed, the Calais LNG Project would supply more natural gas volume to New England than is proposed by Downeast; therefore if constructed, the Calais LNG Project could potentially serve as a system alternative to the Downeast LNG Project. However, because the project is not currently proposed, and it is uncertain if a new or revised project would ever be proposed at the Calais LNG project site, we do not believe that construction of the Calais LNG project would be a viable system alternative. If the Calais LNG project were to be proposed again at some future date, we would conduct a full evaluation of the project, including the potential for the project to be an alternative to the Downeast LNG Project.

**AES Battery Rock LNG Project**

In 2006, AES Corporation announced plans for a proposed LNG import, storage, and regasification facility to be located on Outer Brewster Island within the Boston Harbor Islands State Park, in Boston Harbor. AES indicated the project would provide 0.8 Bcfd sendout capacity and 6.0 Bcf of storage capacity, and would require about 1.2 miles of new pipeline to connect to the existing Algonquin HubLine pipeline and the interstate pipeline system and the northeast natural gas markets. The project would require administrative removal of Outer Brewster Island from the state park. In April 2007, AES announced it would not pursue this project due to competition from the offshore Northeast Gateway and Neptune Projects, and opposition from various groups. Therefore, we do not believe the AES Battery Rock LNG Project is a feasible alternative to the Downeast LNG Project.

### 3.3.2.4 Proposed Offshore Natural Gas Development

New offshore natural gas drilling in coastal New England or Maritimes Canada could potentially provide new sources of natural gas supply to New England. One such project has been identified that may be in production within the general time frame and that could be considered a potential alternative to the proposed Downeast LNG Project.

**Deep Panuke Offshore Gas Development Project**

The Deep Panuke Project is located offshore southeast of Halifax, Nova Scotia, Canada. The project includes an offshore production unit, subsea production wells and connecting pipelines, and a 22-inch subsea pipeline connecting to M&NE's facilities in Goldboro, Nova Scotia. The Deep Panuke Project has a design capacity for production of about 300 MMcfd. A portion of the new production would be sent to the M&NE system, and up to about 200 MMcfd (0.2 Bcfd) would be available to New England markets through the M&NE U.S. system. Construction commenced in November 2008 and gas production began in 2013.

The Deep Panuke Project, through its delivery of natural gas supplies by way of the M&NE pipeline system, provides a new source of natural gas supply to the same New England area market as the Downeast LNG Project, but can provide only about one half the volume of natural gas proposed by Downeast. The Deep Panuke Project does not provide any storage capacity, and would therefore not meet Downeast's objectives of providing natural gas storage facilities. Therefore, the Deep Panuke Project would partially meet the objectives of the Downeast LNG Project, but it could not meet all the objectives. The Deep Panuke Project would also have its own set of environmental impacts, primarily from the development of offshore production facilities, but also from some onshore receiving facilities and associated pipelines. Therefore, we do not believe that the Deep Panuke Project alone would be a reasonable alternative to the Downeast LNG Project.

It is possible that the Deep Panuke Project in combination with some other system alternative(s) could meet the objectives of the Downeast LNG Project. However, Downeast has proposed its project in anticipation of a need for additional natural gas volumes in New England beyond that which would be provided by other reasonably foreseeable energy projects. The Commission must evaluate the merits and associated environmental impacts of the proposed Downeast LNG Project. Despite the current weak economy and resulting short-term decrease in domestic energy consumption, future market demand could justify construction of the Downeast LNG Project, in addition to other proposed and approved projects.

## 3.4 LNG TERMINAL SITE ALTERNATIVES

### 3.4.1 Regional Review

Downeast conducted a Regional Site Selection (RSS) Study to determine a location or locations where an LNG import terminal could be sited to serve the New England market. The RSS Study evaluated prospective LNG terminal sites in coastal New England, including sites where new LNG import terminals have already been proposed by other developers. Site selection criteria included three primary categories: (1) Community Acceptance and Feasibility; (2) Marine Technical and Environmental Issues; and (3) Land Technical and Environmental Issues. For purposes of the RSS Study, an LNG import terminal project was assumed to have the following attributes:

- a marine/river terminal for unloading double-hulled LNG vessels including pier, breasting and mooring dolphins, unloading platform, and cryogenic pipe LNG transfer system;
- one or two LNG double-walled containment storage tanks with an approximate capacity of 160,000 $m^3$;
- regasification process equipment consisting of vapor handling systems and a closed-loop vaporization system capable of handling a sendout rate of 0.5 Bcfd;
- a natural gas connector pipeline of a site-specific distance and market sendout size (estimated to be at least 24-inch-diameter); and
- plant operation systems and facilities for safety control and management, office and employee support buildings, and stormwater control.

Site acreage requirements varied according to site-specific conditions. Sites that were evaluated ranged from 15 acres to more than 100 acres. The RSS Study also considered alternative designs that would minimize environmental impact or enhance safety and operation processes. Such alternatives included, but were not limited to, the following:

- alternative LNG storage tank designs and placement (e.g., partial or wholly excavated LNG tank storage placement, alternative containment type storage tank designs, and lower-profile, broader-based tank designs);

- alternative LNG unloading pier designs, including submerged or floating pipe transfer systems in high tidal fluctuation areas (most of study area);
- alternative regasification systems including sole reliance on clean energy support industries and/or heat exchange systems associated with existing power generation plant(s) wishing to convert from coal to natural gas and elimination of heated water discharges; and
- alternative off-site natural gas pipeline routes utilizing, as much as possible, existing road and/or railroad rights-of-way.

Generally, the RSS Study excluded sites that would have entailed the following:

- the need for a power generation plant as a heating "source" for LNG vaporization;
- an open-loop vaporization system requiring the use of sea water or river water to reheat the LNG for send-out; and
- a pier design and site locale that would require development or maintenance dredging to accommodate deep draft LNG vessels.

Downeast's RSS Study incorporated environmental siting criteria and a valuation ranking system using traditional siting criteria for a coastal LNG import terminal, as well as incorporating public and governmental interests as expressed in local media, trade publications, and public comment forums. The RSS Study also included results of numerous interviews conducted by Downeast throughout the study area covering a broad range of interests and stakeholders. Downeast weighted the site selection criteria in an attempt to be equally representative of community interests, engineering design limitations, and environmental protection. The selection criteria included evaluation of the distance to existing natural gas pipeline transmission infrastructure.

#### 3.4.1.1 Results of RSS Study

Downeast's RSS Study evaluated 27 sites along the coast of New England from New Haven, Connecticut to Robbinston, Maine (figures 3.4-1 and 3.4-2). The site selection evaluation matrix showing results for each of the 27 sites is included in Appendix J of this EIS. The RSS Study ranked each of the sites using the selection criteria discussed above, which resulted in 14 of the 27 sites, and 9 of the top 10 sites being located in Maine. Downeast's proposed Mill Cove site, in Robbinston, Maine, was ranked as number 1. Two other potential sites in the Town of Robbinston were ranked 2 and 3, a site in Perry, Maine was ranked as number 4, and a second site in Perry, at Gleason Cove, was ranked as number 15.

The results of the RSS Study conducted by Downeast show there are a number of potentially suitable locations for new LNG import terminals along the New England Coast. The RSS study also identifies sites that would generally be considered unsuitable for development of an LNG import terminal. We generally agree with the results of the RSS study, however, we note that the selection criteria used by Downeast to rank each location incorporated some level of subjectivity in the weighting of each selection criteria. The rankings also factored in project and company-specific criteria such as acceptable project cost, acceptable level of financial and regulatory risk, and existing or developing relationships with each community. The FERC staff has reviewed and analyzed the results of the RSS Study on the suitability of Downeast's proposed site and whether another site(s) would be a preferred alternative to the proposed site.


**Figure 3.4-1**
**Downeast LNG Project**
**Potential Non-Maine LNG Sites Evaluated in Coastal New England**

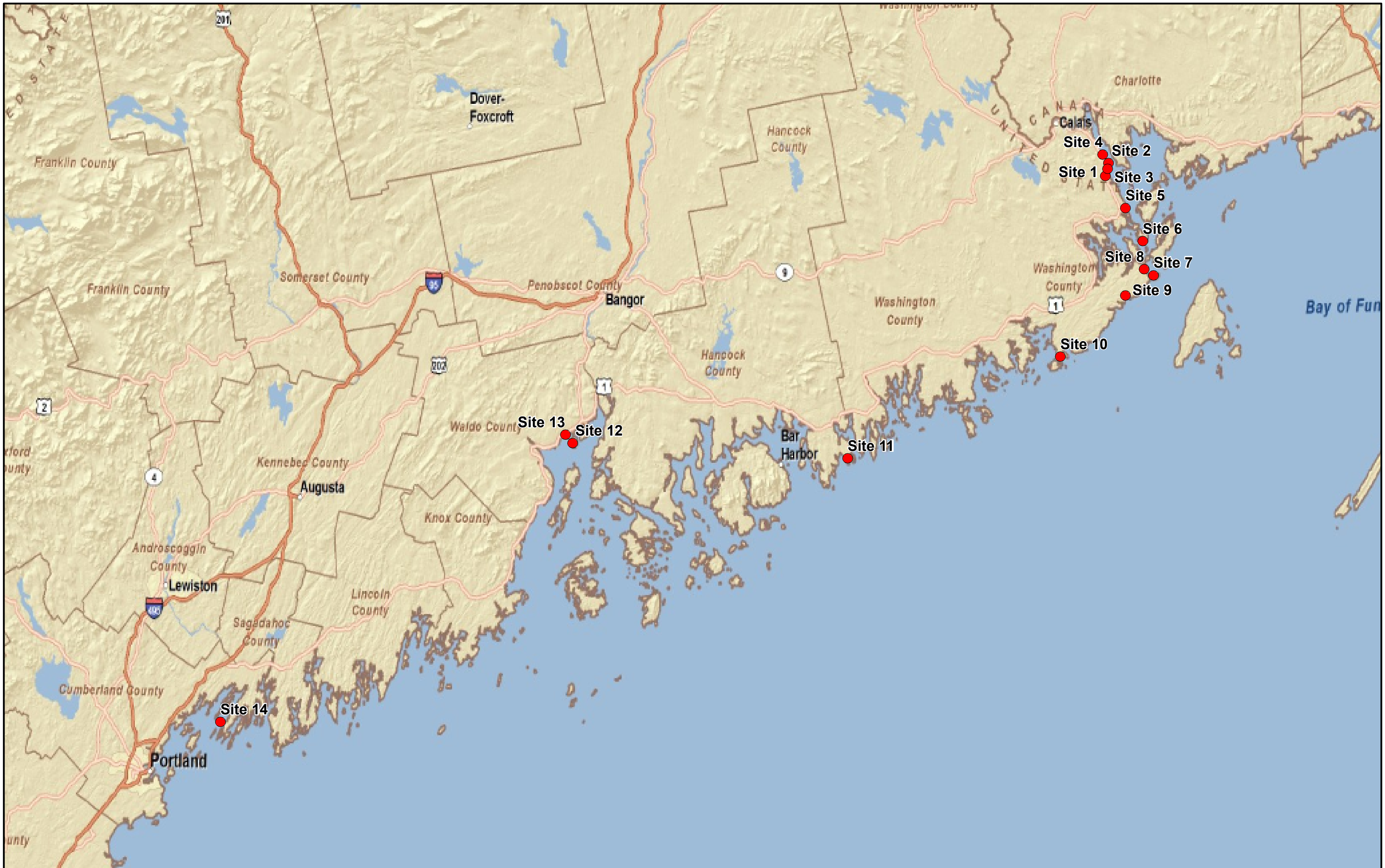



**Figure 3.4-2**
**Downeast LNG Project**
**Potential LNG Terminals in Maine**

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### 3.4.2 Local LNG Terminal Site Location Alternatives

Of the 27 potential sites for LNG terminals included in Downeast's RSS Study, 14 sites were located in Maine (figure 3.4-2). Following is a brief description of the results of Downeast's evaluation of each of these sites and our recommendation for each site.

#### 3.4.2.1 Mill Cove Site, Robbinston, Maine

This site is Downeast's proposed site and is identified as Site Number 3 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, Downeast has a purchase agreement for legal control of the site and exclusion zones (and have since purchased the site); there is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be low; and it was judged to be compatible with existing and future marine and adjacent land uses. It is not in proximity to a large population center; degree of visibility was judged to be low; and there were judged to be no environmentally sensitive species present. Based on the review of site selection criteria, this site was chosen by Downeast as its proposed site.

#### 3.4.2.2 Cannery Site, Robbinston, Maine

This site is an industrial site previously used for a sardine cannery located near the mouth of the St. Croix River in Robbinston, Maine, about 1.5 miles north of the proposed site, and is identified as Site Number 1 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, legal control by Downeast of the site and exclusion zones is feasible; there is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be low; and it was judged to be compatible with existing and future marine and adjacent land uses. It is not in proximity to a large population center; degree of visibility was judged to be low; and there were judged to be no environmentally sensitive species present. Compared to the proposed site, this site would require a slightly longer transit by LNG vessels through Passamaquoddy Bay, and would be slightly closer to the shoreline of St. Andrews across the St. Croix River, possibly increasing its visibility. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of the Cannery Site over the proposed site. Therefore, we do not recommend use of the Cannery Site alternative.

#### 3.4.2.3 Gravel Pit Site, Robbinston, Maine

This site is located on the shoreline of the St. Croix River in Robbinston, Maine, about 1.0 mile north of the proposed site, and is identified as Site Number 2 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, legal control by Downeast of the site is feasible, but control of the entire exclusion zones would require purchase of some homes. There is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be low; and it was judged to be compatible with existing and future marine and adjacent land uses. It is not in proximity to a large population center; degree of visibility was judged to be low; and there were judged to be no environmentally sensitive species present. Compared to the proposed site, this site would require a slightly longer transit by LNG vessels through Passamaquoddy Bay, and would be slightly closer to the shoreline of St. Andrews across the St. Croix River. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of the Gravel Pit Site over the proposed site. Therefore, we do not recommend use of the Gravel Pit Site alternative.

#### 3.4.2.4 Coastal Site, Robbinston, Maine

This site is located on the shoreline of the St. Croix River in Robbinston, Maine, about 3 miles north of the proposed site, and is identified as Site Number 4 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, there are mixed parcels of land in the vicinity of the site and residences that may require purchase within the exclusion zones; there is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be low; and it was judged to be compatible with existing and future marine and adjacent land uses. It is not in proximity to a large population center; degree of visibility was judged to be low; and there were judged to be no environmentally sensitive species present. Compared to the proposed site, this site would require a longer transit by LNG vessels through Passamaquoddy Bay, and would be slightly closer to the shoreline of St. Andrews across the St. Croix River. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of this alternative over the proposed site. Therefore, we do not recommend use of the Coastal Site alternative.

#### 3.4.2.5 Gleason Cove Site, Perry, Maine

This site is located in Gleason Cove in Perry, Maine, about 6 miles south of Downeast's proposed site, and is identified as Site Number 5 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated exclusion zones for the site may extend beyond U.S. Route 1; there is generally sufficient depth and shipping channel width for LNG vessel access, but some limited dredging might be required; potential impact on existing port activities was judged to be high; and it was judged to be compatible with existing and future marine and adjacent land uses. The site is in relatively close proximity to a large population center (Perry); degree of visibility was judged to be high; and there is endangered species habitat present. Compared to the proposed site, this site would include a 6-mile shorter transit by LNG vessels through Passamaquoddy Bay, and would not be visible from St. Andrews. Because the Gleason Cove Site would be in close proximity to a large population center, and due to potential impacts on port activities and impacts from dredging, we do not believe that the Gleason Cove Site offers a significant environmental advantage over the proposed site; therefore, we do not recommend use of the Gleason Cove Site alternative.

#### 3.4.2.6 Estes Head Site, Eastport, Maine

This site is located on Estes Head on the shoreline of Broad Cove, at the southern tip of the peninsula in Eastport, Maine, about 13 miles south of Downeast's proposed site, and is identified as Site Number 6 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated exclusion zones for the site would cover nearby homes; there is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be high; and it was judged to be compatible with existing and future marine uses. Potential impact on existing and future land use was judged to be high. The site is in close proximity to a large population center (Eastport); degree of visibility was judged to be high; and there is no endangered or sensitive species habitat present. This site would also require the sendout pipeline to somehow exit the southern tip of the Eastport peninsula, which would require traversing Cobscook Bay to the south or west, or construction through Eastport to the north and then along or within Route 190 for about 6 miles before exiting the peninsula. Compared to the proposed site, this site would require an LNG vessel transit route about 10 miles shorter than required to reach the proposed site, and would avoid transit through Western Passage and Passamaquoddy Bay. Because the Estes Head Site would be in close proximity to homes and a large population center, and the sendout pipeline would have to cross Cobscook Bay or directly through Eastport, we do not believe the Estes Head Site is environmentally preferable to the proposed site, and therefore, we do not recommend use of the Estes Head Site alternative.

#### 3.4.2.7 Quoddy Head Site, Lubec, Maine

This site is located adjacent to the Coast Guard station on the north side of West Quoddy Head in Lubec, Maine, about 18 miles south of Downeast's proposed site, and is identified as Site Number 7 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated there are nearby homes, but not within the exclusion zones for the site; there is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be low; and it was judged to be compatible with existing and future marine uses. Potential impact on existing and future land use was judged to be low, with the exception of potential impact on recreational use of Quoddy Head State Park. The site is in close proximity to a large population center (Lubec); degree of visibility was judged to be high; and there is potentially sensitive species habitat present. LNG vessels would access this site from around the south side of Campobello Island via the Grand Manan Channel rather than around the north side as would be required for Downeast's proposed site, thus avoiding entirely the need to traverse Western Passage and Passamaquoddy Bay. Because the Quoddy Head Site would be in close proximity to Lubec and due to the potential impact on Quoddy Head State Park, we do not believe the Quoddy Head Site would offer significant environmental advantages over the proposed site; therefore, we do not recommend use of the Quoddy Head Site alternative.

#### 3.4.2.8 South Road Site, Lubec, Maine

This site is located along South Road near Woodward Point in Lubec, Maine, about 17 miles south of Downeast's proposed site, and is identified as Site Number 8 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated there is sufficient land available at the site for the necessary exclusion zones; there is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be low; and it was judged to be compatible with existing and future marine and land uses. The site is not in close proximity to a large population center; degree of visibility was judged to be low; and there is potentially sensitive species habitat present. LNG vessels would access this site from around the south side of Campobello Island via the Grand Manan Channel then through Lubec Channel, rather than around the north side of Campobello Island as would be required for Downeast's proposed site, thus avoiding entirely the need to traverse Western Passage and Passamaquoddy Bay. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of the South Road Site over the proposed site. Therefore, we do not recommend use of the South Road Site alternative.

### 3.4.2.9 Bailey's Mistake Site, Lubec, Maine

This site is located within a bay called Bailey's Mistake at the southern end of the township of Lubec, Maine, about 22 miles south of Downeast's proposed site, and is identified as Site Number 9 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated there is sufficient land available at the site for the necessary exclusion zones and no houses are present within those zones; there is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be low; and it was judged to be compatible with existing and future marine and land uses. The site is not in close proximity to a large population center; degree of visibility was judged to be low; and there is potentially sensitive species habitat present. LNG vessels would access this site from the Grand Manan Channel. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of the Bailey's Mistake Site over the proposed site. Therefore, we do not recommend use of the Bailey's Mistake Site alternative.

### 3.4.2.10 Cutler Former Navy Base Site, Cutler, Maine

This site is located within the former Cutler Navy Base on Little Machias Bay, in Cutler, Maine, about 36 miles south of Downeast's proposed site, and is identified as Site Number 10 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated there is sufficient land available at the site for the necessary exclusion zones and no houses are present within those zones; however, control would have to be obtained from the Navy. There is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be medium; and it was judged to be compatible with existing and future marine and land uses, although it would be in close proximity to high recreational use areas (Cross Island NWR). The site is not in close proximity to a large population center; degree of visibility was judged to be medium; and there is potentially sensitive species habitat present. LNG vessels would access this site from the Grand Manan Channel. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of the Cutler Navy Base Site over the proposed site. In addition, Cutler Residential Development, LLC has constructed a residential community on the site, Beachwood Bay Estates, consisting of 62 condominium units and associated amenities. Therefore, we do not recommend use of the Cutler Navy Base Site alternative.

### 3.4.2.11 Gouldsboro Former Navy Base Site, Gouldsboro, Maine

This site is located on the former Navy Base on Prospect Harbor in the Town of Gouldsboro, Maine, about 70 miles south of Downeast's proposed site, and is identified as Site Number 11 on figure 3.4-2 and in table J-1 in Appendix J. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated there is sufficient land available at the site for the necessary exclusion zones and no houses are present within those zones; however, control would have to be obtained from the U.S. government. There is sufficient depth and shipping channel width for LNG vessel access with no dredging required; an existing dock for large ships; potential impact on existing port activities was judged to be medium; and it was judged to be compatible with existing and future marine and land uses, although it would be in close proximity to high recreational use areas in Prospect Harbor. The site is not in close proximity to a large population center; degree of visibility was judged to be medium; and there is potentially sensitive species habitat present. LNG vessels would access this site directly from the Gulf of Maine. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of the Gouldsboro Navy Base Site over the proposed site that would justify using the Gouldsboro Navy Base Site instead of the proposed site. In addition, Cianbro Corp. declined to pursue an LNG terminal on the former Navy base. The Navy intends to transfer a portion of the site to the National Park Service, and another portion is being handed over to the town of Gouldsboro, Maine. There have also been discussions for a number of years about constructing an Aquaculture Business Park on the site of the former Navy communications center, which could house up to 15 businesses involved in land-based commercial aquaculture activities. Therefore, we do not recommend use of the Gouldsboro Navy Base Site alternative.

#### 3.4.2.12 Sears Island Site, Searsport, Maine

This site is located on former Navy property on Sears Island in Penobscot Bay in the Town of Searsport, Maine, about 95 miles south of Downeast's proposed site, and is identified as Site Number 12 on figure 3.4-2 and in table J-1 in Appendix J. The site is currently owned by the state. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated there is sufficient land available at the site for the necessary exclusion zones and no houses are present within those zones; however, control would have to be obtained from the state. There is sufficient depth and shipping channel width for LNG vessel access with no dredging required; potential impact on existing port activities was judged to be medium; and it was judged to be compatible with existing and future marine and land uses, although it would be in close proximity to high recreational use areas in Penobscot Bay and shoreline areas. The site is not in close proximity to a large population center; degree of visibility was judged to be medium, but with a high number of potential viewers; and there is potentially rare species habitat present. To reach this site, LNG vessels would have to traverse about 25 miles up Penobscot Bay to the mouth of the Penobscot River. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of the Sears Island Site over the proposed site. Therefore, we do not recommend use of the Sears Island Site alternative.

#### 3.4.2.13 Mack Point Site, Searsport, Maine

This site is located on Searsport Harbor in Penobscot Bay, across from Sears Island, in Searsport, Maine, about 95 miles south of Downeast's proposed site. The site is identified as Site Number 13 on figure 3.4-2 and in table J-1 in Appendix J. The site is currently an industrial port operated by Sprague Energy and the Montreal, Maine, and Atlantic Railway. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated there is sufficient land available at the site for the necessary exclusion zones and no houses are present within those zones; however, control would have to be obtained from the current operators. There is sufficient depth and shipping channel width for LNG vessel access; however, dredging would be required for a turning basin to accommodate LNG vessels. Potential impact on existing port activities was judged to be medium, and it was judged to be compatible with existing and future marine uses. Potential impact on existing and future land use of the site and surrounding areas was judged to be high, and it would be in close proximity to high recreational use areas in Penobscot Bay and shoreline areas. The site is not in close proximity to a large population center; degree of visibility was judged to be medium; and there were no known rare or sensitive species present. To reach this site, LNG vessels would have to traverse about 25 miles up Penobscot Bay to near the mouth of the Penobscot River. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of the Mack Point Site over the proposed site. Therefore, we do not recommend use of the Mack Point Site alternative.

#### 3.4.2.14 Harpswell Former Navy Site, Harpswell, Maine

This site is located on a former Navy fuel depot facility on Harpswell Neck in Casco Bay in the Town of Harpswell, Maine, about 180 miles south of Downeast's proposed site. The site is identified as Site Number 14 on figure 3.4-2 and in table J-1 in Appendix J. The site is currently controlled by the Town of Harpswell. Of the major site selection criteria evaluated by Downeast, preliminary evaluation indicated there is sufficient land available at the site for the necessary exclusion zones and no houses are present within those zones; however, control would have to be obtained from the town. There is sufficient depth and shipping channel width for LNG vessel access with no dredging required. Potential impact on existing port activities was judged to be medium, and it was judged to be compatible with existing and future marine uses, with an existing dock present. Development of the site for an LNG terminal was judged to be consistent with existing and potential future land use, although it would be in close proximity to high recreational use areas in Casco Bay and surrounding shoreline areas. The site is not in close proximity to a large population center; degree of visibility was judged to be medium; and there are potential habitat for sensitive species present. To reach this site, LNG vessels would have to traverse about 8 miles through Casco Bay. This site was the site of a previously planned LNG terminal project (Fairwinds LNG), which was cancelled in March 2004 after the Town of Harpswell voted against leasing the property to the project proponent. Although this site was judged to be suitable for an LNG import terminal, we have not identified significant environmental advantages of the Harpswell Former Navy Site over the proposed site. In addition, because a previous LNG import project was proposed for the site but denied by the Town of Harpswell, the feasibility of this site is questionable. Therefore, we do not recommend use of the Harpswell Former Navy Site alternative.

## 3.5 MARINE FACILITY ALTERNATIVES

Downeast evaluated five alternative designs for the marine unloading terminal. Each alternative would meet the same general facility requirements including a single berth able to unload LNG vessels from 70,000 $m^3$ to 220,000 $m^3$ capacity; the unloading platform would be capable of supporting the necessary LNG unloading and vapor return equipment; and all marine facilities would be located within the site's conceptual property limits determined from imaginary lines extending perpendicular from the land site property borders. The marine facility alternatives that were evaluated are discussed below.

### 3.5.1 Long Trestle – Straight Alignment (Proposed Design)

Downeast's proposed marine facility design consists of a long trestle with a straight alignment. This alternative would include locating the unloading platform so that LNG vessels would have access to a natural water depth of at least 45 feet and extending an above-water access trestle from the shore to the unloading platform. The trestle would be linear, extending in a straight line from the shoreline about 3,862 feet. The trestle would provide access for personnel and vehicle traffic as well as for the piping to transport the product to the LNG storage tanks. Preliminary information obtained by Downeast indicates seabed composition would be rock along about two-thirds of the trestle length, with soft bottom for the remainder. Where the seabed is rock, trestle support piles would require rock-socketed pile foundations, and traditional driven piles could be used for soft bottom.

Advantages of the proposed design include access to LNG facilities, pipelines, and utilities for operation, maintenance, and emergency response vehicles and personnel that would be provided by a road along the trestle from the onshore facility to the waterside facilities. This design would also avoid the need for dredging and the associated environmental impacts, since the trestle would extend the necessary distance from shore to reach the natural water depth of 45 feet. Another advantage of this alternative is that it is a traditional design in common use for other LNG facilities, and has a proven record of performance and constructability. Also, this alternative may increase public safety since it would place the unloading platform at a distance from shore that would be far removed from an ignition source onshore should there be a spill event on the unloading platform or LNG vessel.

Disadvantages of this alternative would include visual and noise impacts on the surrounding areas because of the length of the trestle extending from the shoreline. This impact may be greatest for residents located on North Mill Cove, as well as across Passamaquoddy Bay in St. Andrews. Visual impacts would include view of the trestle during the day, as well as lighting on the trestle at night. Visual impacts are discussed further in section 4.7.4. In addition, the COE, New England District, has published guidelines for the placement of fixed and floating structures in navigable waters of the United States that are regulated by the New England District (COE 1996). The guidelines suggest that no structures on a linear waterway should extend more than 25 percent of the waterway width at mean low water. The proposed pier design appears to extend just over 25 percent of the width of the St. Croix River/Passamaquoddy Bay at the Project location, depending on where the width is measured between the irregular shoreline on both the United States and Canadian sides of the waterway. The guidelines are not policy or regulation, and would typically not result in COE permit denial. In its review of the project-specific section 404/401 permit for the Project, the COE would determine if the proposed pier design would be acceptable for the site-specific conditions.

### 3.5.2 Long Trestle – Bent Alignment

This alternative would involve a trestle similar to the proposed alternative, except the trestle would include a bend mid-way along its length and would be about 440 feet longer than the proposed straight trestle. The alternative trestle would begin by extending perpendicular to the shoreline for about 2,200 feet in a slightly more northeast direction than the proposed trestle. This portion of the trestle would be shoreward of the mean low water line. The trestle would then bend to the east for about 2,100 feet until reaching a natural water depth of at least 45 feet. This alternative would place the end of the trestle and the LNG unloading platform about 1,900 feet northwest of the proposed location. Downeast evaluated this alternative partly to reduce the length of trestle that would be within the navigational waterway to address the New England COE navigational guideline regarding pier length into linear waterways (COE 1996). Downeast also evaluated the alternative because it would require less rock-socketed pile foundations, and was also initially believed to allow greater accommodation of weir fishing south of the trestle than would be allowed by the proposed trestle placement.

The primary advantages of a long trestle with bent alignment would be the same as for the proposed trestle design: access to LNG facilities, pipelines, and utilities for operation, maintenance, and emergency response vehicles and personnel that would be provided by a road along the trestle from the onshore facility to the waterside facilities. This alternative would avoid the need for dredging and the associated environmental impacts, since the trestle would extend from shore the necessary distance to reach natural water depth of 45 feet. This alternative is a traditional design in common use for other LNG facilities, has a proven record of performance and constructability, and may also increase public safety since it would place the unloading platform at a distance from shore that would be far removed from an ignition source onshore should there be a spill event on the unloading platform or LNG vessel. An advantage of this alternative over the proposed trestle design is that the alternative would traverse less hard rock bottom, which would allow greater use of traditional piles and less use of rock-socketed pile foundations. Traditional piles can be installed faster and with less bottom disturbance than rock-socketed piles. Another advantage of this alternative is that it would reduce visual and noise impacts for residents across Passamaquoddy Bay in St. Andrews by increasing the distance from the pier.

This alternative would place the trestle and unloading platform much closer to the shoreline along the north shore of Mill Cove; therefore, potential visual and noise impacts on the Mill Cove shoreline areas would be greater for this alternative than for the proposed trestle design. This alternative trestle design would be less than 500 feet from the shoreline of Mill Cove where the trestle would bend to the northeast near Mill Point. By comparison, at the closest point the proposed alignment would be about 1,700 feet from Mill Point. Because this alternative would be about 440 feet longer than the proposed trestle design, it would also require more pilings and associated bottom disturbance than the proposed design. Downeast initially felt the bent trestle design may have less impact on weir fishing than the proposed straight trestle design. However, Downeast states that based on discussions with weir fishermen, the bent trestle design would not be expected to reduce potential impact on weir fishing over the proposed straight trestle design. We do not believe the potential advantages of this alternative outweigh the disadvantages, and do not believe this alternative would be environmentally preferable over the proposed trestle design. Therefore, we do not recommend use of the alternative using a long trestle with a bent alignment.

### 3.5.3 Short Trestle with Dredging

As an alternative to extending the trestle the full distance from shore necessary to reach the natural water depth of 45 feet, Downeast evaluated shorter trestle lengths combined with dredging. Downeast evaluated trestle lengths that would be 100, 500, and 1,000 feet shorter than the proposed long trestle. The area of dredging and volume of dredged material would be necessarily greater as the trestle is shortened. Based on estimates of bottom type, dredging necessary for this alternative would also require underwater blasting. Except for the shorter length, the trestle design of this alternative would be similar to the proposed design.

The primary advantages of a shorter trestle with dredging would include those of the proposed trestle design – access to LNG facilities, pipelines, and utilities for operation, maintenance, and emergency response vehicles and personnel that would be provided by a road along the trestle from the onshore facility to the waterside facilities. This alternative would be a traditional design in common use for other LNG facilities, and has a proven record of performance and constructability. An additional advantage of this alternative over the proposed trestle design is that the alternative would extend a shorter distance from shore and therefore may be less visible from certain areas along the north shoreline of Mill Cove and from St. Andrews. The alternative would also extend a shorter distance into navigable waters, which would be in line with the COE navigational guidance (COE 1996), and could result in less impact on marine navigation. The alternative would also require fewer piles than the proposed trestle design because of its shorter length.

The primary disadvantages of this alternative would include those of the proposed trestle design – visual and noise impacts on onshore communities. Because the trestle under this alternative would be shorter, these impacts could be somewhat less than the proposed design depending on the visual vantage point onshore. However, even if the trestle were 1,000 feet shorter than the proposed design, the trestle would extend about 2,800 feet from shore and would be visible from most locations along the shoreline of Mill Cove that currently have a view of the cove. Therefore, this alternative would not significantly reduce visual impacts. Noise impacts on onshore areas from activities on the LNG vessels and unloading platform would be slightly higher for this alternative than the proposed trestle design because the noise sources would be closer to shore. Another major disadvantage of this alternative is that it would require dredging and blasting in order to create the water depth necessary for LNG vessels to reach the LNG unloading platform at the end of the shorter trestle. Dredging and blasting would result in short-term impacts on the marine bottom habitats and surrounding aquatic resources from bottom disturbance, turbidity, noise, and settling of sediment on adjacent bottom habitats. Long-term impacts could also result from periodic maintenance dredging required to maintain the depth of the channel.

During scoping, we received a comment that the EIS should also evaluate use of shallower draft vessels that may allow use of a shorter trestle design but without the need for dredging. Downeast's proposed action is based on a depth of the berth and channel of 45 feet to allow for LNG vessels from 70,000 $m^3$ to 220,000 $m^3$ capacity. Draft of LNG vessels of this range generally varies by less than 2 feet. Therefore, some reduction in the amount of dredging could be achieved by limiting the project to smaller vessels. However, there are only a small number of the smallest sized LNG vessels in the worldwide fleet, with the most common sized LNG vessels in the range of 125,000 to 150,000 $m^3$. We do not believe the potential advantages of the short trestle alternative, with or without dredging, outweigh the disadvantages, and do not believe that this alternative would be environmentally preferable over the proposed trestle design. Therefore, we do not recommend use of the alternative using a short trestle.

### 3.5.4 Sea Island with Submarine Pipelines

This alternative would eliminate the trestle entirely, and instead would involve building the LNG unloading platform as a sea island with no physical above-water connection to the shore. The unloading platform would be placed at the same location as the proposed design in sufficient water depth to accommodate LNG vessels without the need for dredging. With this alternative, personnel would access the LNG unloading platform and berth by small marine craft. This alternative would require construction of a pier for small craft and tugs that would be usable at all tides, which would extend an estimated 1,000 feet from shore. The piping which carries the

LNG product to the shore would be located as a submarine type unit. A trench would be excavated for the submarine pipelines for most of the distance. At the shore interface, the pipeline would be installed by HDD and brought up into the LNG storage tank area to avoid an approximately 60-foot-high bluff along the shoreline.

The primary advantage of this alternative is that it would eliminate the visual impact associated with the above-water trestle. When an LNG vessel is not at berth, the visible components of the marine facilities would be the LNG unloading platform, which at its closest point would be about 3,862 feet from shore, and a pier for small craft and tugs. Downeast states that by eliminating the trestle, this alternative may also provide for continued use of the existing fish weirs in Mill Cove.

The primary disadvantage of this alternative is the significant amount of dredging and blasting that would be necessary to excavate the trench for the nearly 4,000 feet of submerged pipelines between the LNG unloading platform and shore. Dredging and blasting would result in bottom disturbance, turbidity, noise, and settling of sediment on adjacent bottom habitats. This alternative would limit access to the LNG unloading platform and berth for operation, maintenance, repair, and emergency response equipment and personnel. This alternative would provide no access for trucks or cranes, and access by other equipment would be by barge. Personnel access would be by multiple daily shuttles of a small launch to and from shore, with a harbor tug likely required during severe weather conditions. Access to the submerged pipelines for maintenance and repair could take significantly longer than for pipelines on the proposed aboveground trestle. Downeast states that the limited access allowed by this alternative would substantially reduce operational flexibility.

Because the sea island alternative with submerged pipelines would result in a significant amount of blasting and dredging for installation of the pipelines, and because this impact would be avoided by use of the proposed pier design, we do not believe this alternative would provide an environmental advantage over the proposed design. In addition, while this alternative would eliminate the visual impact of the trestle, it would still include visual impact from approximately 1,000 feet of new pier. Therefore, we do not recommend use of the sea island alternative with submerged pipelines.

### 3.5.5 Sea Island with Pipelines in Directionally Drilled Tunnel

This alternative would be similar to the sea island alternative with submarine pipelines, as it would eliminate the trestle entirely and would involve building the LNG unloading platform as a sea island with no physical above-water connection to the shore. However, for this alternative, the pipelines from the LNG unloading platform to the onshore LNG storage tanks would be installed in a directionally drilled tunnel rather than by trenching. The tunnel would be ten feet in diameter, which is beyond the size for typical HDD technology. The tunnel would be constructed by a tunnel boring machine or conventional horizontal drill and blast. The unloading platform would be placed at the same location as the proposed design in sufficient water depth to accommodate LNG vessels without the need for dredging. Personnel would access the LNG unloading platform and berth through the tunnel. This alternative would require construction of a pier for small craft and tugs that would be usable at all tides, which would extend an estimated 1,000 feet from shore. This alternative would include construction of one tunnel for LNG product pipelines.

The primary advantage of this alternative is the same as for the sea island with submerged pipelines – the visible components of the marine facilities would be substantially less than the proposed trestle, and it would eliminate the visual impact associated with the above-water trestle. When an LNG vessel is not at berth, the visible components of the marine facilities would be the LNG unloading platform, which at its closest point would be about 3,862 feet from shore, and approximately 1,000 feet of pier for small craft and tugs. Downeast states that by eliminating the trestle, this alternative may also provide for continued use of the existing fish weirs in Mill Cove. This alternative would also require no dredging or blasting, either for deepening of the LNG berth or for installation of pipelines.

The primary disadvantage of this alternative is limited access to the LNG unloading platform and berth for operation, maintenance, repair, and emergency response equipment and personnel. This alternative would provide for no access for trucks or cranes, and any access by other large equipment would be by barge. Downeast states that the limited access allowed by this alternative would reduce operational flexibility.

Because the pipelines in this alternative would be installed in a directionally drilled tunnel rather than by blasting and dredging, environmental impacts of this alternative would be substantially less than impacts from the dredging that would be required for the sea island alternative with submarine pipelines. However, Downeast's marine geotechnical investigation indicated that the subsurface material underlying the trestle area is bedrock from the shore out to approximately 1,000 feet and then becomes soft marine sediment deposits the remainder of the distance out to the unloading platform. The sediments are very soft and could not support the superimposed weight of a tunnel without significant settlement and a high likelihood of failure. Because geotechnical investigations show that underlying sediments could not support the weight of a tunnel, we have eliminated this alternative from further consideration.

## 3.6 LNG VAPORIZATION ALTERNATIVES

LNG is vaporized, or returned to natural gas, by heating the LNG; there are a number of alternative LNG vaporization processes currently available. Downeast's proposed design includes the use of SCVs for LNG vaporization. In addition to SCVs, Downeast analyzed potential use of open rack vaporizers (ORVs), heat integrated ambient air vaporizers (HIAAV), and shell and tube vaporizers (STVs) with low temperature heat transfer fluid (HTF).

### 3.6.1 Submerged Combustion Vaporizers (Proposed Vaporization)

SCVs are composed of stainless steel tubes that are submerged in a water bath containing a submerged combustion chamber. The combustion chamber burns a low-pressure natural gas and is supplied with air via an electric air blower. The heated exhaust from the combustion chamber is sent to the water bath containing the stainless steel tubes with the LNG flowing inside and transfers the heat needed to vaporize the LNG. SCV technology is a closed loop system that does not require water intake and discharge; however, condensate water is produced from the combustion process. The primary advantages of the SCV technology are its compact size, high thermal efficiency, closed loop water use, and ease of operation and maintenance. Disadvantages are the release of regulated air emissions generated during the combustion process, and potential discharge of condensate water if it is not reused. Downeast selected SCVs as its proposed regasification system based on the suitability of the system to the site location and terminal operational requirements, and based on its desire to use a closed loop system to minimize impact on the marine aquatic environment.

### 3.6.2 Open Rack Vaporizers

ORVs are widely used where LNG facilities are located in close proximity to a readily available supply of seawater. They are made of aluminum alloy and use seawater as a sole source of heat. Pumps are used to move the seawater from an overhead distributor over long-finned aluminum panels with the LNG flowing inside. Vaporization of the LNG is accomplished by transferring heat from the seawater to the LNG. As the seawater passes over the aluminum panels, it is cooled and collected in troughs at the bottom of the ORV before it is discharged back into the water source. Vaporization effectiveness depends on seawater temperature, which must be at least 46°F and preferably warmer. The primary advantages of ORV technology are its operational flexibility, ease of maintenance, stable heat transfer, and limited fuel consumption and air emissions. The primary disadvantages of this technology are the withdrawal and discharge of large volumes of seawater, and potential impingement and entrainment of organisms during withdrawal and thermal impacts on the receiving waterbody during discharge. This technology also has limited effectiveness in northern climates where the source of water is below 46°F for much of the year. Because this vaporization technology would require use of large volumes of seawater, and the withdrawal and discharge of seawater would involve potential additional environmental impacts on aquatic systems, we do not believe that use of ORVs would provide an environmental advantage over the proposed use of SCVs, and therefore do not recommend use of ORV vaporization for the Downeast LNG Project.

### 3.6.3 Combined Loop (SCVs and ORVs)

It is also possible to vaporize LNG using a combined loop system that incorporates both SCV and ORV technology. For example, this could be used in northern climates where ORV technology could be used when water temperatures are above 46°F, and SCV used for the remainder of the year. Such a combined system would require additional space on site to incorporate both systems. Because a combined loop system at the proposed Downeast LNG site would require seawater intakes during operation using ORV technology, we do not believe this alternative would provide an environmental advantage over the proposed use of SCV, and therefore, we do not recommend use of a combined loop vaporization system for the Downeast LNG Project.

### 3.6.4 Heat Integrated Ambient Air Vaporizers

HIAAVs take heat from the surrounding air and transfer it to vaporize LNG as it passes through an exchanger. The natural convection of air and subsequent heat transfer rate would be enhanced by the height of the exchanger. HIAAVs are set up in trains and each train is equipped with four vaporizers. The primary advantages of the HIAAV technology are the use of surrounding air in the heating process, little to no emissions during the warmer months, no noise generation from heating fans, and no use of intermediate fluids or secondary exchangers. The primary disadvantages with this vaporization technology are its sensitivity to changes in air temperature, humidity, and wind speed; potential to create fog on warm days; production and disposal of water; and the need for a backup system during cooler months. Because of these potential disadvantages, we do not believe use of HIAAV would provide an environmental advantage over use of SCVs, and therefore do not recommend use of HIAAV vaporization for the Downeast LNG Project.

### 3.6.5 Shell and Tube Vaporizers

STVs are compact vaporizers with a high heat transfer coefficient. LNG is vaporized by passing the LNG through a series of tubes that are surrounded by an external fluid. This external fluid could consist of seawater in a single-pass seawater system or an intermediate fluid consisting of a water and glycol mix, propane, or ammonia in a closed loop system. In a single-pass seawater system, the seawater would be contained within the shell. The LNG would enter vaporizer tubes at a bottom channel cover, pass through an exchanger, and exit at a top channel cover. Seawater would enter through the side of the exchanger at an upper and lower inlet where it would be circulated over the tubes with the LNG flowing inside and warming it to a gaseous state where it would exit at the top of the shell. STV technology using a single-pass seawater system requires an abundant supply of seawater. The primary disadvantages of this technology are fouling and maintenance of the shell and tube exchangers, frequent periods of downtime for maintenance, potential freezing of the shell and tubes, and impingement and entrainment of marine organisms. We do not recommend use of this alternative for these reasons.

Although alternative LNG vaporization technologies exist, use of these technologies for the Downeast LNG Project would likely result in a similar level of (although different) environmental impacts, and in some cases (ORV and STV) potentially greater environmental impacts. We believe that use of alternative LNG vaporization technologies for the Downeast LNG Project would not provide any significant environmental advantage over the proposed use of SCVs, and therefore do not recommend use of an alternative vaporization technology.

## 3.7 LNG VESSEL DESIGN ALTERNATIVES TO REDUCE WATER USAGE

NOAA Fisheries requested that the EIS include an analysis of alternative LNG vessel designs that could reduce water usage, similar to alternative vessel designs in use for the Northeast Gateway and Neptune offshore LNG projects (see section 3.3.2.1 of this EIS). LNG vessels calling on the Downeast LNG terminal would be at the terminal an average of about 21 hours. While at the terminal, each vessel of approximately 145,000 $m^3$ could cycle up to 40 million gallons of seawater (vessel). This water would be used for engine cooling and for ballast water (one-time use of 15 million gallons).

The LNG vessels calling on the Northeast Gateway and Neptune offshore LNG ports would have similar seawater usage requirements while at the offshore port facilities (estimated to be eight days per visit). However, unlike the typical LNG vessels that would call on the Downeast LNG terminal, the vessels calling on the Northeast Gateway and Neptune ports are specially designed to include on-board regasification of LNG. The requirements of on-board regasification of LNG provide unique opportunities for use of seawater heat exchangers between the LNG regasification system and normal vessel operational cooling systems. Such heat exchangers enable the on-board regasification vessels to operate under a closed-loop heat recovery and exchange mode while active regasification of LNG is underway, which reduces average daily water use while at port from approximately 56 mgd to 5 mgd.

Because the proposed Downeast LNG terminal is designed for accepting and storing natural gas in its liquid phase, the LNG vessels calling on the terminal would be of conventional design and not equipped with regasification system components such as those described above. Therefore, the opportunity to utilize alternative LNG vessel designs are not available to the Downeast LNG Project.

## 3.8 PIPELINE LOCATION ALTERNATIVES

In evaluating alternatives for Downeast's sendout pipeline, we reviewed both route alternatives and route variations. We examined route alternatives that could reduce or avoid impact on environmentally sensitive resources such as special-use areas, waterbodies, and extensive wetlands. Route alternatives generally follow a different alignment for a long segment of the proposed route. Route variations differ from route alternatives in that they are generally short deviations identified to avoid or reduce construction impacts on specific, localized resources that may include cultural resource sites, residences, site-specific terrain conditions, or specific landowner concerns.

### 3.8.1 Pipeline Route Alternatives

#### 3.8.1.1 Alternatives Affecting the Moosehorn NWR

We evaluated three pipeline route alternatives that would each cross a portion of the Moosehorn NWR. These alternatives are generally described below and shown in Appendix K figure K-1. However, because of the FWS's decision denying Downeast's application request for a right-of-way across NWR lands, these alternatives are not considered feasible, and therefore are not analyzed in detail in this EIS.

#### 3.8.1.2 Original Proposed Route (Option 4)

Downeast's original proposed route, called Option 4 in Downeast's application, would cross 3.5 miles of the Moosehorn NWR. This route was included in Downeast's application to the FWS requesting a right-of-way across refuge lands, and which was denied by the FWS based on its determination that the pipeline is not a compatible land use. Because of this determination, we believe this is not a reasonable alternative and have not analyzed it in further detail in this EIS.

#### 3.8.1.3 Moosehorn/Railway Alternative

The Moosehorn/Railway Alternative, called Option 1 in Resource Report 10 of Downeast's application, was Downeast's original preferred route for the sendout pipeline. The alternative would be within an inactive Maine Central railway grade for about 9.2 miles, and would cross about 6.5 miles of the Moosehorn NWR. Downeast determined it would not be able to secure an irrevocable lease from the current owner of the rail right-of-way, the Maine Department of Transportation (Maine DOT). Without an irrevocable lease, the railway must be kept available for possible future reactivation, in which event Downeast would be required to relocate the pipeline and disrupt service. Therefore, Downeast dropped this route as its preferred route. Because this alternative would require crossing the Moosehorn NWR and the FWS has determined that a pipeline crossing of the refuge is not a compatible land use, we believe this is not a reasonable alternative and have not analyzed it in further detail in this EIS.

### 3.8.1.4 Howard Lake Alternative

The Howard Lake Alternative is a segment of the pipeline route alternative Downeast identified as Option 2 in its application. The alternative would begin at MP 2.2 of the proposed route and turn west-northwest following existing secondary and unimproved roads and a portion of inactive Maine Central railway grade for about 9.3 miles, ending within the Moosehorn NWR. The advantage of this alternative is that it would be about 3.8 miles shorter than the corresponding segment of proposed route, thus reducing the area of construction disturbance. However, the alternative would cross about 3.0 miles of the Moosehorn NWR. Because this alternative would require crossing the Moosehorn NWR and the FWS has determined that a pipeline crossing of the refuge is not a compatible land use, we believe this is not a reasonable alternative and have not analyzed it in further detail in this EIS.

### 3.8.1.5 Western Alternative

The Western Alternative is a segment of the pipeline route alternative Downeast identified in its application as Option 5. The Western Alternative would entirely avoid crossing the Moosehorn NWR.

The Western Alternative would begin at the Downeast LNG terminal at MP 0.0 of the proposed route, and would follow U.S. Route 1 north for about 0.5 mile, turn southwest and follow Ridge Road for about 5.2 miles to the intersection with South Meadow Road, and then follow South Meadow Road for about 4.6 miles. The alternative would then turn west/northwest for about 20.5 miles along new right-of-way before ending at the proposed pipeline route at MP 28.2 at the existing M&NE pipeline at the crossing of U.S. Route 1 northwest of Woodland. In this section, the alternative would cross the Dennys River, pass south and then west of Meddybemps Lake, and would cross the western edge of the area known as Meddybemps Heath. The alternative is shown on figure K-1 in Appendix K. Table 3.8.1.5-1 compares major environmental characteristics of the Western Alternative with the corresponding segment of proposed route.

TABLE 3.8.1.5-1

**Comparison of the Western Alternative with the Corresponding Segment of Proposed Route**

| Environmental Factor | Corresponding Segment of Proposed Route | Western Alternative |
|---|---|---|
| Total Length (miles) | 27.0 | 30.8 |
| Length Adjacent to Existing Rights-of-Way (miles) | 9.8 a/ | 10.3 |
| Construction Disturbance (acreage) b/ | 245.4 | 280.0 |
| Wetlands Affected (acres) c/ | 23.28 | 52.8 |
| Waterbodies Crossed (number) | 24 | 12 |
| Length within Moosehorn NWR (miles) | 0.0 | 0.0 |
| Residences within 50 feet of Construction Work Area (number) | 2 | 53 |

a/ Does not include placement adjacent to a planned new electric transmission right-of-way between MPs 0.2 and 11.6.
b/ Based on nominal right-of-way width of 75 feet.
c/ Determined from NWI mapping for alternative, and field delineation for corresponding segment of proposed route.

The primary advantage of the Western Alternative is that it would cross 12 fewer waterbodies than the corresponding segment of the proposed route, including avoiding a crossing of the

St. Croix River. The alternative would also avoid the Moosehorn NWR. The disadvantages of the Western Alternative include longer length, greater wetland impact, and more residences within 50 feet of the construction right-of-way than the corresponding segment of proposed route. In addition, as mapped by Downeast, the 10.3 miles of the alternative that would be adjacent to existing rights-of-way would be within or immediately adjacent to roadways. It is unlikely that pipeline construction could be accomplished for such long distances within these roadways as envisioned by Downeast, and that an offset from these roadways would be required to avoid residential and other developments and to minimize traffic disruptions.

Also, if the Downeast LNG Project were approved, EMEC would construct a 69-kV electric transmission line from its existing substation in Milltown to a new substation along U.S. Route 1 directly across from the LNG terminal site. It is anticipated that Downeast's proposed pipeline route would be adjacent to, and the right-of-way would partially overlap, about 11.4 miles of this EMEC right-of-way. Installation of the transmission line would occur during construction of the LNG terminal, prior to construction of the sendout pipeline. Therefore, if the project were approved, it is anticipated that the proposed pipeline route would be adjacent to about 11.4 miles of recently created right-of-way. This would be in addition to the currently existing rights-of-way that the proposed pipeline would be adjacent to. This would increase the environmental advantage of the corresponding segment of proposed route over the Western Alternative.

We believe the disadvantages of this alternative outweigh its advantages, primarily due to increased impacts on residential areas, increased wetland impacts, and constructability issues associated with roadway construction. Therefore, we believe the alternative would not be environmentally preferable to the corresponding segment of proposed route. Therefore, we do not recommend use of the Western Alternative.

### 3.8.2 Pipeline Route Variations

During review of the proposed sendout pipeline, we identified route variations that may avoid or minimize environmental impact on specific sensitive areas or areas of concern. We evaluated these route variations to determine if they would be environmentally preferable to the corresponding segments of the proposed route.

#### 3.8.2.1 Baring Plantation Variation

In a letter filed with the Commission on March 17, 2008, a local resident recommended a route variation that would avoid the Baring Plantation residential community near MP 17. Construction of the sendout pipeline along this suggested route variation potentially would impact up to 24 vernal pools or their 250-foot buffers. Downeast did evaluate this route variation as part of its design of the amended pipeline route; this option was eliminated from further consideration due to the impacts on the vernal pools and their associated wetland communities. We concur with this evaluation.

#### 3.8.2.2 Route Variations for Residences within 50 feet of the Permanent Right-of-Way

In October 2009, Downeast filed modified site-specific residential construction plans, and subsequently revised those plans in January 2010. The January 2010 plans included route variations to minimize impacts on the 19 residences located within 50 feet of the permanent sendout pipeline right-of-way. These variations are incorporated into Downeast's proposed route for the sendout pipeline that is analyzed in section 4 of the EIS.

Downeast has modified its proposed route to include the following route variations to minimize impacts on each residence that was previously located within 50 feet of the permanent right-of-way. The residence located near MP 0.63 was 49 feet from the proposed permanent right-of-way and within a proposed ATWS area. Downeast now proposes to reduce the permanent right-of-way width by 5 feet so that it is 54 feet from the structure and to eliminate the ATWS. The ATWS on the other side of Ridge Road is at least 50 feet from the residence.

The residence located near MP 0.91 was previously 6 feet from the permanent right-of-way and within a pipe laydown area. Downeast now proposes to move the pipeline route to the west closer to Sweeney Road and reduce the size of the pipe laydown area so that both would be more than 50 feet away from the residence.

For the one residence located near MP 1.35 that was previously within the temporary right-of-way and the two residences located near MP 1.45 that would be within the permanent right-of-way, Downeast now proposes to continue the HDD pipe installation located at MP 1.11 to extend 50 feet beyond the edge of the residential structures, position a new 25-foot by 200-foot HDD ATWS at the south end of the extended HDD installation, position a new 50-foot by 743-foot pipe laydown area at the south edge of that new HDD ATWS, and position a new 12.5-foot by 200-foot HDD ATWS at its north edge. With this variation, the proposed construction work area is now over 600 feet from the residence at MP 1.35, and would be about 110 feet from the residences at MP 1.45 at the closest point.

There is one residence located near MP 5.16 that was previously within the permanent right-of-way. Downeast now proposes to create a new HDD installation beginning at MP 5.1 and continue in a straight line to MP 5.24, create a 17,500 square foot HDD ATWS and a new 25-foot by 200-foot HDD ATWS near the southeastern end of the new HDD installation at MP 5.1. In addition, Downeast proposes to create a 50-foot by 549-foot laydown area and a 25-foot by 200-foot HDD ATWS near the northwestern end of the new HDD installation at MP 5.27 and remove the two ATWS on Shattuck Road. With this variation, the construction work area would be about 250 feet from the residence near MP 5.16 at the closest point.

For the residences located near MPs 23.94, 23.97, 24.01, 24.05, 24.09, 24.12, 24.15, 24.17, 24.19, 24.21, 24.27, 24.32, and 24.48, Downeast has incorporated a route variation that would now relocate the pipeline right-of-way closer to the U.S. Route 1 right-of-way; combine the 50-foot by 600-foot laydown area located at MP 24.20 and the 25-foot by 200-foot HDD ATWS located at MP 24.28 into one 25-foot by 750-foot laydown area located between the right-of-way and U.S. Route 1; relocate the 25-foot by 200-foot HDD ATWS located at MP 24.41 between the right-of-way and U.S. Route 1; and remove each 25-foot by 200-foot HDD ATWS on the northwest side of the pipeline at each end of the HDD. This variation would now move the pipeline centerline at least 75 feet away from each of the listed residences, and the temporary construction workspace at least 50 feet from the residences.

The January 2010 site-specific plans depicting these route variations are included in Appendix P of the final EIS. The route variations generally result in reduced impacts on these residences.

### 3.8.3 Single or Collocated Sendout Pipelines

We received comments during scoping that the EIS should evaluate a single sendout pipeline that could be used for a combination of either the Downeast LNG and Quoddy Bay LNG Projects, or the Downeast LNG and Calais LNG Projects, or two pipelines as proposed, but located adjacent to each other to the extent possible to avoid creation of two new rights-of-way.

These alternatives were analyzed in detail in the draft EIS; however, both the Quoddy Bay and Calais LNG Projects are no longer proposed. As described in section 3.3.2.3, the Commission dismissed Quoddy Bay's application on October 17, 2008 and Calais LNG's application on April 4, 2012. Therefore, we do not believe the alternatives of a single or collocated sendout pipelines are feasible, and have not analyzed them in this EIS.

# 4.0 ENVIRONMENTAL ANALYSIS

The environmental consequences of constructing and operating the proposed Downeast LNG Project would vary in duration and significance. Four levels of impact duration were considered: temporary, short-term, long-term, and permanent. Temporary impact generally occurs during construction with the resource returning to preconstruction condition almost immediately afterward. Short-term impact could continue for up to three years following construction. Impact was considered long-term if the resource would require more than three years to recover. A permanent impact could occur as a result of any activity that modifies a resource to the extent that it would not return to preconstruction conditions during the life of the project, such as the construction of an LNG terminal. We considered an impact to be significant if it would result in a substantial adverse change in the physical environment.

In this section, we discuss the affected environment, general construction and operational impacts, and proposed mitigation for each resource. We have also included a discussion on the waterway for LNG marine traffic, including the potential impacts on environmentally sensitive resources along the waterway.

Downeast, as part of its proposal, agreed to implement certain measures to reduce impact. We evaluated Downeast's proposed mitigation to determine whether additional measures are necessary to reduce impact. These additional measures appear as bulleted, boldfaced paragraphs in the text. We recommend that these measures be included as specific conditions to authorizations that the Commission may issue to Downeast.

Conclusions in this EIS are based on our analysis of the environmental impact and the following assumptions:

- Downeast would comply with all applicable laws and regulations;
- the proposed facilities would be constructed as described in section 2.0 of this document; and
- Downeast would implement the mitigation measures included in the application and supplemental filings to the FERC.

## 4.1 GEOLOGIC RESOURCES

### 4.1.1 Geologic Setting

Maine, New Hampshire, and Massachusetts are part of the New England Physiographic Province, which forms a portion of the Appalachian Highlands Division. The region is subsequently divided into three major physiographic zones: the White Mountain, the New England Upland, and the Seaboard Lowland sections. The project crosses the two latter sections. The New England Upland occupies northern, eastern, and central Maine. It is an area with moderate relief characterized by hills and low mountains from a few hundred feet to about 1,500 feet. The Seaboard Lowland in Maine, New Hampshire, and Massachusetts lies along the coast between the New England Upland and the Atlantic Ocean. It varies in width from about 20 miles near the New Hampshire border to about 60 miles near the New Brunswick border. This section has generally low relief and elevations typically of less than 400 feet, except for occasional hills and low mountains in isolated spots.

Much of the landscape was shaped by Wisconsinian glaciation that created the many hills and glacial features still present today. As the glaciers began to melt around 13,000 years ago, sea level rose to cover the isostatically depressed coastal Lowland and the marine sediments of the Presumpscott Formation, depositing a sand, silt, and clay mixture (Thompson and Borns 1985). Other land features were created from either direct deposition by the ice or meltwater from the ice. Typical glacial features encountered in the project area include glacial till, glaciomarine sediments, glaciofluvial deposits, and moraines.

#### 4.1.1.1 Surficial Geology

##### 4.1.1.1.1 Waterway for LNG Marine Traffic

Offshore surficial geology includes recently deposited (Holocene) muds and sands within Passamaquoddy Bay that overlie 15 to 82 feet of well-stratified glaciomarine muds from the Presumpscott Formation. In some areas, there are layers of sand at the base of this formation. Beneath this stratum is an unsorted, unstratified till mixture of fine and coarse rock debris that unconformably overlies bedrock and varies considerably in thickness. Additional geotechnical investigations of the trestle and berthing dock area would be necessary to support the final design of the trestle foundation.

Other than activities associated with construction of the trestle and berthing dock, dredging or disturbance is not anticipated in the waterway for LNG marine traffic. No significant impacts on surficial geology would be expected along the waterway for LNG marine traffic from the increase in LNG traffic.

##### 4.1.1.1.2 LNG Terminal

Along the offshore portion of the LNG terminal, surficial geologic conditions vary with distance from shore. Near the shoreline, the uppermost surficial materials are river bottom deposits, including sands and silts (1.0 to 13.5 feet thick). With increasing distance from shore, these materials transition to shallow marine clays (12 to 24 feet thick). Both the river bottom deposits and shallow marine deposits are underlain by marine clay (20 to 60 feet thick) with occasional marine sand (2.3 to 4.0 feet thick), which in turn are underlain by glacial till (7.0 to 20.5 feet thick) and bedrock.

The surface of the landside portion of the LNG terminal is characterized by a limited thickness (0.2 to 2.5 feet) of forest mat/topsoil consisting primarily of silty sand with roots and organic matter. Directly below this layer is the marine clay of the Presumpscott Formation, which varies in thickness from 2 to 79 feet and overlies a limited area of glacial till (0.3 to 4.9 feet thick). Sand and gravel were also encountered beneath the forest mat/topsoil stratum in some portions of the site. The material ranges in thickness from approximately 2.0 to 8.7 feet and consists of red-brown, well-graded sand with gravel that appears to be derived from the underlying bedrock.

The primary effect of construction on geology would consist of permanent disturbance to the existing topography within the construction footprint of the facility. To the greatest extent possible, areas disturbed during construction outside of the facility footprint would be finish-graded and restored as closely as possible to preconstruction contours during cleanup and restoration.

#### 4.1.1.1.3 Sendout Pipeline

The route of the sendout pipeline passes over a variety of glacially derived deposits. These deposits include glacial till, glaciomarine sediments, swamp marsh and bog deposits, and eskers. Approximately 17.0 miles (57.0 percent) of the pipeline corridor cross till deposits; 10.1 miles (33.9 percent) cross glaciomarine sediments; 2.1 miles (7.0 percent) cross swamp marsh and bog deposits; and 0.6 mile (2.0 percent) crosses esker deposits.

The primary effect of construction on surficial geology would consist of disturbances to the existing topography along the pipeline construction right-of-way. All areas disturbed during pipeline construction would be finish-graded and restored as closely as possible to preconstruction contours during cleanup and restoration.

### 4.1.1.2 Bedrock Geology

Bedrock in the project area originated as sediments deposited in shallow, subsiding ocean basins and solidified into sedimentary rocks such as conglomerate, sandstone, pelite, and carbonate rocks. Minor amounts of ash and larger fragments derived from offshore volcanic islands also contributed material. These sedimentary rocks were later folded, faulted, and subjected to extreme pressure and temperatures during two major episodes of geologic plate movement and mountain building to metamorphose into slate, phyllite, schist, gneiss, quartzite, metavolcanic and calc-silicate rocks. During the last regional tectonic event, igneous rock such as granite, quartz monzonite, and monzodiorite intruded into the surrounding host rock.

#### 4.1.1.2.1 Waterway for LNG Marine Traffic

Bedrock along and underlying the LNG marine waterway generally consists of Devonian and Silurian age intrusive rock from the Eastport and Leighton Formations, respectively. Further to the north approaching the terminal site, the channel bedrock becomes a medium hard, fresh to moderately weathered sandstone, while adjacent to the terminal site a moderately hard to hard, fresh to moderately weathered, red conglomerate is found, similar to the materials found at the land-side terminal facilities.

Bedrock along the waterway for LNG marine traffic would not be affected by construction or operation of the proposed project. No significant impacts on bedrock would be expected along the waterway for LNG marine traffic from the increase in LNG traffic.

#### 4.1.1.2.2 LNG Terminal

Bedrock in the terminal area generally consists of moderately hard, fresh, coarse-grained conglomerate. Based on a preliminary geophysical survey performed by Downeast, bedrock is within 5 feet of the surface in some portions of the site. Generally, the upper 1 to 2 feet of bedrock is weathered and highly fractured. Downeast estimates approximately 170,000 cubic yards of rock would need to be removed to construct the foundations for the LNG storage tanks, transfer area spill containment basin, process area spill containment basin, vaporizer area spill containment basin, and the trestle abutment structure. Most of these structures are located in the central and eastern portions of the terminal site and the nearest area is approximately 500 feet from U.S. Route 1. The rock would be removed using a combination of excavating equipment and blasting. Rock generated from excavation for the LNG storage tanks and spill containment basins would be processed to be used as structural fill beneath the proposed buildings, roadways, and other ancillary facilities.

Offshore surveys show the depth to the top of bedrock (relative to the ocean bottom) increased from west to east and ranged from 31.0 to 77.3 feet (elevation [El.] -52 to El. -133 feet). The top of rock was encountered at approximately El. -103 and El. -106 at the proposed locations of the northernmost and southernmost mooring dolphins, respectively. At the proposed location of the unloading platform, the top of rock is approximately 30 feet deeper (approximately El. -134). Blasting would not be required to construct the pier foundation elements, although as stated above, some blasting may be required to construct the trestle abutment structure onshore.

Blasting activities would adhere to all local, state, and federal regulations applying to controlled blasting and blast vibration limits in regard to structures and underground utilities, including but not limited to Occupational Safety and Health Administration (OSHA) regulations (29 CFR § 1910.109, Explosives and Blasting Agents). Local regulations require that a blasting permit be obtained on the municipal level as well as through Maine DEP. An activity-specific blasting plan would be prepared prior to any blasting. The construction contractor would follow applicable procedures and would be responsible for notifying officials, obtaining appropriate blasting permits or permission, and providing any necessary bond or insurance.

#### 4.1.1.2.3 Sendout Pipeline

The proposed sendout pipeline route traverses the following bedrock formations:

- Sandstone and Conglomerate – A medium-grained, clastic sedimentary rock composed of abundant rounded or angular fragments of sand size, with or without a fine-grained matrix (silt or clay), and more or less firmly united by a cementing material. This is the same bedrock underlying the storage terminal and offshore facilities.
- Devonian-Ordovician Flume Ridge Formation – A variable mix of calcareous sandstones, siltstones, and slates.
- Devonian Granite – A plutonic rock (a large body of intrusive igneous rock) with quartz constituting 10 to 50 percent of the felsic components, and the alkali feldspar/total feldspar ratio generally restricted to the range of 65 to 90 percent.
- Devonian gabbro/diorite/ultramafic rocks - quartz diorite – A mixture of intrusive and plutonic rocks.
- Cookson Formation – A well-sorted sulfide quartzose sandstone.

Along the sendout pipeline, the depth to bedrock varies from surface outcrops to greater than 30 feet below ground surface (bgs). Approximately 8.86 miles (29.7 percent) of shallow bedrock are likely to be encountered; these intervals are summarized in table 4.1.1.2.3-1. In addition, 1.45 miles (4.9 percent) of areas with unknown depth to bedrock are located along the sendout pipeline; these intervals are summarized in table 4.1.1.2.3-2. The majority of bedrock underlying the proposed pipeline is considered hard; therefore, areas of shallow bedrock would likely require blasting or other special construction techniques during pipeline installation.

TABLE 4.1.1.2.3-1

**Locations of Shallow Bedrock (Less Than 5 Feet Below Ground Surface) Along the Proposed Downeast Pipeline**

| Milepost From | Milepost To | Length (miles) | Formation / Rock Type | Depth to Bedrock (inches) a/ |
|---|---|---|---|---|
| 0 | 0.22 | 0.22 | Sandstone and Conglomerate | 10 |
| 0.29 | 0.55 | 0.26 | Sandstone and Conglomerate | 10 |
| 0.68 | 1.01 | 0.33 | Sandstone and Conglomerate | 10 |
| 1.31 | 1.89 | 0.58 | Sandstone and Conglomerate | 10 to 38 |
| 2.08 | 2.17 | 0.09 | Sandstone and Conglomerate | 10 |
| 2.3 | 3.12 | 0.82 | Sandstone and Conglomerate; Devonian Granite | 10 to 15 |
| 4.34 | 4.41 | 0.07 | Devonian Granite | 20 |
| 4.51 | 4.62 | 0.11 | Devonian Granite | 20 |
| 4.7 | 4.83 | 0.13 | Devonian Granite | 20 |
| 5.52 | 5.8 | 0.28 | Devonian Granite | 15 |
| 5.89 | 6.61 | 0.72 | Devonian Granite | 15 to 38 |
| 6.74 | 6.81 | 0.07 | Devonian Granite | 15 |
| 6.84 | 7.65 | 0.81 | Devonian Granite | 15 |
| 7.71 | 7.87 | 0.16 | Devonian Granite | 15 |
| 7.97 | 8.57 | 0.6 | Devonian Granite; Devonian gabbro/diorite/ultramafic rocks - quartz diorite | 15 |
| 8.66 | 9.44 | 0.78 | Devonian gabbro/diorite/ultramafic rocks - quartz diorite | 15 |
| 9.47 | 10.14 | 0.67 | Devonian gabbro/diorite/ultramafic rocks - quartz diorite | 15 |
| 10.14 | 10.19 | 0.05 | Devonian gabbro/diorite/ultramafic rocks - quartz diorite | 15 |
| 10.27 | 10.34 | 0.07 | Devonian gabbro/diorite/ultramafic rocks - quartz diorite | 15 |
| 10.44 | 10.46 | 0.02 | Devonian gabbro/diorite/ultramafic rocks - quartz diorite | 15 |
| 10.62 | 10.69 | 0.07 | Devonian gabbro/diorite/ultramafic rocks - quartz diorite | 15 |
| 10.72 | 10.92 | 0.2 | Devonian gabbro/diorite/ultramafic rocks - quartz diorite | 15 |
| 12.04 | 12.14 | 0.1 | Devonian gabbro/diorite/ultramafic rocks - quartz diorite | 15 |
| 12.36 | 12.75 | 0.39 | Devonian gabbro/diorite/ultramafic rocks - quartz diorite; Devonian Granite | 15 |
| 13.03 | 13.07 | 0.04 | Devonian Granite | 15 |
| 13.08 | 13.59 | 0.51 | Devonian Granite | 15 to 38 |
| 13.63 | 13.68 | 0.05 | Devonian Granite | 38 |
| 15.9 | 15.92 | 0.02 | Devonian Granite | 38 |
| 15.94 | 16 | 0.06 | Devonian Granite | 38 |
| 16.75 | 16.82 | 0.07 | Devonian Granite | 38 |
| 17.13 | 17.23 | 0.1 | Devonian Granite | 38 |
| 17.53 | 17.74 | 0.21 | Devonian Granite | 38 |
| 19.76 | 19.96 | 0.2 | Cookson Formation – sulfidic quartzose sandstone | 15 |
| | **Total Length** | **8.86** | | |

a/ Depth to bedrock is the distance from the soil surface to the top of a bedrock layer, expressed as a shallowest depth of components whose composition in the given soil map unit is equal to or exceeds 15%.

Source: USDA 2006a.

Where consolidated rock (such as sandstone and conglomerate) is encountered during construction, Downeast's preferred procedure would be to fracture and excavate the bedrock using standard construction equipment. During any excavation, the trench would be approximately 6 to 7 feet deep to provide a minimum of 3 feet of cover for the pipeline. However, if crystalline bedrock (such as granite or basalt) is encountered and cannot be easily removed by conventional excavation methods, blasting techniques would be utilized in compliance with state and federal regulations governing the use of explosives. Only the minimum explosive charge necessary to fracture bedrock and keep shot-rock from leaving the construction right-of-way would be utilized. The contractor would conduct pre-blasting evaluations of the rock, with landowner permission, to develop specific blasting operations and monitoring plans to limit stresses on existing pipelines, nearby domestic structures, water supply wells, or electrical transmission tower footings that are located near the project area. Peak particle acceleration velocities would be recorded to ensure operations are conducted within a safe limit.

TABLE 4.1.1.2.3-2

**Locations of Unknown Depth to Bedrock Along the Proposed Downeast Pipeline a/**

| Milepost From | Milepost To | Length (miles) | Formation / Rock Type |
|---|---|---|---|
| 13.59 | 13.63 | 0.04 | Devonian Granite |
| 13.68 | 13.73 | 0.05 | Devonian Granite |
| 14.17 | 14.23 | 0.06 | Devonian Granite |
| 14.3 | 14.81 | 0.51 | Devonian Granite |
| 14.98 | 15.21 | 0.23 | Devonian Granite |
| 15.26 | 15.55 | 0.29 | Devonian Granite |
| 20.95 | 21.01 | 0.06 | Cookson Formation – sulfidic quartzose sandstone |
| 22.12 | 22.16 | 0.04 | Cookson Formation – sulfidic quartzose sandstone |
| 25.42 | 25.52 | 0.1 | Devonian-Ordovician Flume Ridge Formation |
| 28.65 | 28.72 | 0.07 | Devonian-Ordovician Flume Ridge Formation |
| | **Total Length** | **1.45** | |

a/ There are some soil types for which depth to bedrock has not been characterized by USDA – NRCS. Along the proposed Downeast pipeline, these soils include: Marlow fine sandy loam, Buxton silt loam, pits, sand and gravel, Udorthents-Urban land complex, and water. Because depth to bedrock is not known, these soils may potentially overlie shallow bedrock.
Source: USDA 2006a.

Potential impacts from blasting on wells located within 150 feet of the project boundaries include decreased yields, decreased water quality (i.e., increased turbidity or odor), interference with well operation, or disruption of well function. According to Downeast, there are no public water supply wells located within 150 feet of the construction right-of-way in areas of shallow bedrock for the terminal and sendout pipeline. Therefore, Downeast does not anticipate any impacts on public drinking water wells due to blasting.

The sendout pipeline would cross the wellhead protection area (WPA) for the Baileyville Utility District (BUD) between approximately MP 25.4 and MP 25.6, and between approximately MP 28.6 and MP 28.7. At the first location, Wells #1 and #2 would be more than 150 feet north of the pipeline right-of-way. Potential impacts of sendout pipeline construction and operation on the WPA are discussed in section 4.3.1.3. Construction and operation of the pipeline is not expected to have permanent effects to groundwater flow patterns or aquifers.

Downeast has stated that it would not be able to identify private water supply wells until agreements with landowners to access land for this purpose are granted; therefore, we have recommended that Downeast file the location of all private wells and springs within 150 feet of construction activities prior to construction (see section 4.3.1.3). If any blasting is required within 150 feet of a water well, pre- and post-blasting well testing, with authorization from the owner, would be performed to ensure there is no loss of productivity and quality. In the unlikely event that such impacts would have occurred, Downeast would implement remedial actions to restore the well to its pre-blasting condition.

Disposal of rock and rock debris from trenching and blasting would be in areas approved by the individual landowners or land management agency in accordance with Downeast's Plan, Procedures, and Soil Erosion and Sediment Control Guidelines, and regulatory requirements. Mixing of excavated rock material with backfill or soil would be minimized and rock would not be replaced in an excavation at an elevation higher than the original rock surface. Excess rock material would be windrowed along the right-of-way with the permission of the landowner. In sensitive areas such as cultivated land, the excess rock would be removed from the area. Should Downeast have to dispose of excess rock outside of the right-of-way, an approved landfill or alternative upland area would be utilized and the appropriate permits and clearances would be obtained.

### 4.1.2 Mineral Resources

Mineral extraction activities in the project area generally consist of granite quarries, and sand and gravel operations. These operations are described below.

#### 4.1.2.1 Waterway for LNG Marine Traffic

No mineral resources were found along the waterway for LNG marine traffic; therefore, there would be no impacts on mineral resources from the LNG marine traffic.

#### 4.1.2.2 LNG Terminal

There are no granite quarries or sand and gravel pits on the terminal site. No mineral resources were identified at or adjacent to the site. The nearest mineral resources are surface sand and gravel operations that are approximately 5.5 miles to the west-southwest of the facility.

#### 4.1.2.3 Sendout Pipeline

The sendout pipeline does not traverse any mines, quarries, or gravel pits; however, at MP 23.4 (Baileyville) and MP 24.4 (Princeton), three former borrow pits were identified in the vicinity of the pipeline route. They are located more than 0.5 mile from the proposed pipeline and are considered abandoned or in long disuse. The proposed pipeline would not impact these former borrow pits.

In the event other mineral resources are identified, Downeast would negotiate with the affected landowners/operators as part of the right-of-way procurement process to obtain an easement agreement that governs excavation activities in the immediate vicinity of the permanent pipeline right-of-way and/or establish an adequate buffer zone between active excavation areas and the proposed pipeline. Losses or limitations on sand and gravel operations (current or future expansion) would be addressed during those easement negotiations.

### 4.1.3 Paleontological Resources

Paleontological resources are the fossilized remains of prehistoric plants and animals, as well as the impressions left in rock or other materials as indirect evidence of the forms and activities of such organisms. A variety of geological processes, including erosion and sedimentation, mountain-building, deformation (folding and faulting), metamorphism, and igneous activity, have removed a large portion of Maine's and coastal New Hampshire's and Massachusetts' fossil record (Marvinney 2006). The bedrock underlying the entire proposed project is conglomerate, metamorphic or intrusive in character, and has generally undergone sufficient heat and pressure to eliminate any fossils that may have been in the pre-metamorphic ancestral sedimentary rock. Therefore, it is not anticipated that paleontological resources would be encountered in any area impacted by the project.

### 4.1.4 Geologic Hazards

Geologic hazards potentially of greatest significance to the project include seismicity and faulting, soil liquefaction, slope failures/landslides, and ground subsidence.

#### 4.1.4.1 Seismicity and Faulting

Hazards associated with seismicity include ground shaking, surface rupture of faults, and earthquake induced ground failures such as landslides and lateral spreading due to soil liquefaction.

Historic earthquake activity in the northeastern United States has primarily been limited to events of relatively small magnitude (magnitude less than 5). However, since 1638, at least 14 earthquakes with magnitudes greater than 5 have been recorded in New England and southeast Canada (New Brunswick and Quebec). Prior to 1900, historically recorded earthquakes in Maine occurred mainly in the coastal zone in the Eastport and Penobscot Valley areas. Most earthquakes occurred to the southeast of the Norumbega Fault System. Modern and historical records indicate the areas of higher seismic activity in Maine include the Passamaquoddy Bay area of eastern Washington County; Dover-Foxcroft-Milo area of southern Piscataquis County; and in southwestern Maine, the Portland-Lewiston Region of Androscoggin and Cumberland Counties (Berry 2005).

The most concentrated time period of observed earthquakes occurred between approximately 1870 and 1900 in the Passamaquoddy Bay area (Smith et al. 1989). The two most significant earthquakes that occurred near this time period are the Passamaquoddy Bay earthquake of 1869 and the Eastport area earthquake of 1904. The Passamaquoddy Bay earthquake has been classified as intensity VII earthquake based on the Modified Mercalli Intensity (MMI) scale, and the magnitude estimated at 5.7 (Leblanc and Burke 1985). The Eastport area earthquake has been classified as an intensity VI earthquake on the MMI scale, and the magnitude has been estimated at 5.9 (Leblanc and Burke 1985). According to seismic events based on data from the Weston Observatory and the Maine Geological Survey (MGS) from 1747 to 1992, there are a significant number of recorded earthquakes from Eastport to Calais and surrounding areas including Passamaquoddy Bay. With the exception of the earthquakes discussed above, the recorded earthquake magnitudes in this region range from less than 2 to 4.9 (Johnston and Anderson 1995).

#### 4.1.4.1.1 LNG Terminal and Sendout Pipeline Facilities

The above historic activity indicates there is a low but steady rate of seismic activity in Maine where the LNG terminal and sendout pipeline would be located. Possible causes of earthquakes in the New England region include focusing of regional stresses at plutons and possible small-scale introduction of magma into plutons at depth (Krinitzsky et al. 1993). Ebel (1989) references post-glacial isostatic rebound and reactivation of ancient faults through tectonic plate motion as theories for Maine earthquakes. This persistent activity indicates evidence of crustal deformation. However, there is no evidence to associate recorded earthquake locations with an active fault zone based on known local or regional geologic features (Ebel 1989).

Several major faults exist in the project region, including the Oak Bay Fault and the Norumbega Fault Zone. Review of the physiographic and historical data for the project area indicates no evidence for geologically recent movement along these faults. Consequently, the potential for seismicity associated with surficial fault displacement does not represent a significant risk to the proposed project. It is also significant to note that pipelines using modern arc-welding techniques have performed well in seismically active areas of the United States, including California (O'Rourke and Palmer 1996).

Only large, abrupt ground displacements have caused serious impacts on pipeline facilities. Due to the very limited potential for large, seismically induced ground movements in the project area (Frankel et al. 2002), there is very little risk of earthquake-related impacts on the pipeline facilities. The seismic risk and design requirements for the LNG terminal are discussed below.

**Geological Hazards, Site-Specific Geotechnical Investigations and Seismic Hazard Analyses**

Haley & Aldrich (2007) conducted an initial geotechnical site investigation and probabilistic seismic hazard analysis for the proposed LNG terminal site and provided the results in reports dated June 2006 as part of the formal Downeast application. A supplemental geotechnical site investigation was completed in September 2007 based on Downeast's subsequent rearrangement of the plant layout. The findings and conclusions regarding geological hazards, foundation design requirements, and seismic design are summarized below.

**Foundation Design**

The LNG storage tanks would be constructed on reinforced concrete mat foundations bearing directly on bedrock. It would be necessary to excavate up to 14 feet of rock for tank T-201A and up to 27 feet of rock for tank T-201B to construct the mat foundations. Borings completed in the area of tank T-201A revealed a zone of highly weathered and fractured rock that would require further investigation prior to detailed foundation design. Rock excavated for the tank foundations would be used to construct the shore-side rock barrier and storm water management systems.

Downeast LNG's facilities must be constructed to satisfy the design requirements of 49 CFR 193, NFPA 59A-2001, 2006 International Building Code, and American Society of Civil Engineer (ASCE) 7-05. For seismic design, the facility would also be designed to satisfy the requirements of NFPA 59A-2006 and ASCE 7-05. Based on currently available information, the site is not likely to be subject to seismic soil liquefaction or lateral spreading, ground failure due to sinkholes, or landslides, although additional slope stability and bearing capacity analyses would be required in final design.

**Seismic Category I Input Ground Motions**

Input Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE) reference rock motions for Seismic Category I structures were determined from probabilistic seismic hazard maps developed by the USGS in 2002 for exceedance probabilities of 10 percent and 2 percent in 50 years, respectively. These reference rock values were then adjusted using one-dimensional site response analysis techniques to account for soil amplification at the site. The 2 percent probability of exceedance in 50-year spectrum, corrected for the site soil column, is the SSE spectrum, but is also referred to as the Maximum Considered Earthquake (MCE) spectrum. The 5 percent-damped horizontal SSE spectral acceleration values at peak ground acceleration (i.e., zero period), 0.2-second period, and 1.0-second period were determined as 0.15 g, 0.38 g and 0.12 g, respectively. The same values for the OBE spectrum were determined as 0.04 g, 0.08 g and 0.02 g. The ground motions for Category I structures have been determined in a manner that satisfies the requirements of NFPA 59A-2006.

**Seismic Category II and III Input Ground Motions**

The USGS probabilistic seismic hazard maps at the 2 percent probability of exceedance in 50 years form the basis of the MCE mapped values found in the 2006 IBC and ASCE 7-05. Based on the subsurface information collected to date, the site is underlain by relatively stiff overburden soils, generally consisting of up to 10 feet of dense to very dense granular soils (sand/gravel) and/or very stiff cohesive soils (silt/clay), which overlies bedrock. Downeast would locate all proposed Seismic Category II and III structures at or below current site grades, such that the foundation elements of the structures would bear directly on naturally-deposited, inorganic soils, and not on organic soils or man-placed, engineered fill. The Seismic Site Class has been determined for ancillary structures in accordance with Chapter 20 of ASCE 7-05. Based on the available data, Seismic Category II and III structures and components would be designed using a Site Class C profile (very dense soil and soft rock).

The following design values would be used for MCE ground motion parameters:

- Mapped Spectral Accelerations for Short Periods: SS = 0.319g
- Mapped Spectral Accelerations for 1-Second Periods: S1 = 0.072g
- Long-Period Transition Period: TL = 6 seconds
- MCE Spectral Response Acceleration for Short Periods: SMS = 0.383g
- MCE Spectral Response Acceleration for 1-Second Periods: $S_{M1}$ = 0.122g

Note that "g" refers to acceleration due to gravity.

The following design values would be used for Design Earthquake (DE) ground motion parameters:

- DE Spectral Response Acceleration for Short Periods: SDS = 0.255g
- DE Spectral Response Acceleration for 1-Second Periods: SD1 = 0.081g

Construction and operation of the project would not materially alter the geologic conditions of the project area, and the project would not affect mining of resources during construction or operation. Blasting is anticipated during construction of the project, but appropriate precautions would be taken to protect dwellings and water supplies. Based on Downeast's Plan, Procedures, and Soil Erosion and Sediment Control Guidelines, and our recommended mitigation measures, we conclude that impacts on geological resources would be adequately minimized and would not be significant and the project would not be affected by any significant geologic hazards, including areas of seismic activity or subsidence.

The design of the facilities is currently at the Front End Engineering Design (FEED) level of completion. A feasible design has been proposed, and Downeast would conduct a significant amount of detailed design work if the project is authorized by the Commission. Information regarding the development of the final design would need to be reviewed by FERC staff in order to ensure that the final design addresses the requirements identified in the FEED. Therefore, **we recommend that:**

- **Downeast should file the following information, stamped and sealed by the professional engineer-of-record, with the Secretary for review and written approval by the Director of OEP:**

  **a) structure and foundation design drawings and calculations of the LNG tanks and other LNG import terminal facilities;**

  **b) seismic specifications used in conjunction with the procuring equipment; and**

  **c) quality control procedures that will be used for design and construction.**

  **In addition, Downeast should file, in its Implementation Plan, the schedule for producing this information.**

#### 4.1.4.2 Soil Liquefaction

Soil liquefaction from severe ground shaking causes cohesionless soil to lose strength. This generally occurs in saturated soils when water completely fills the available pore space between soil particles. Soil liquefaction can result in surface settlement where the ground surface is flat or in lateral spreading where the ground surface is sloped.

##### 4.1.4.2.1 Waterway for LNG Marine Traffic

Soil liquefaction along the waterway for LNG marine traffic is considered to be minimal as fine-grained, saturated soils prone to liquefaction are generally not found in the high energy water environment of the waterway. No significant impacts from soil liquefaction would be expected along the waterway for LNG marine traffic.

#### 4.1.4.2.2 LNG Terminal

Within the Downeast LNG terminal vicinity, geotechnical borings were made during the seismic investigation and soil boring logs reviewed. The overburden consists of stiff to hard clay and medium dense to very dense sand with a total thickness varying from 4.0 to 12.8 feet. Based on the dense nature of the soils present above the bedrock, grading of soil particles, the measured depth to the water table, and location in an area of low seismic risk, soil liquefaction is unlikely. Additionally, many of the critical onshore and offshore structures would be supported on bedrock.

#### 4.1.4.2.3 Sendout Pipeline

Soils along the sendout pipeline route are similar to those in the LNG terminal area. Based on the nature of these soils and the location in an area of low seismic risk, soil liquefaction is unlikely.

### 4.1.4.3 Subsidence

Ground subsidence is a lowering of the land-surface elevation that results from changes that take place underground. Common causes of land subsidence include dissolution of limestone in areas of karst terrain; collapse of underground mines; and pumping of water, oil, and gas from underground reservoirs.

#### 4.1.4.3.1 Waterway for LNG Marine Traffic

There is no active underground mining or pumping of oil and gas from underground reserves or large groundwater withdrawals from large water supplies along the waterway for LNG marine traffic. Consequently, subsidence due to underground mining or resource extraction is not likely to occur along the proposed LNG vessel transit route. No significant impacts from subsidence would be expected along the waterway for LNG marine traffic. Karst terrain is discussed below.

#### 4.1.4.3.2 LNG Terminal

There is no active underground mining or pumping of oil and gas from underground reserves or large groundwater withdrawals in the LNG terminal area. Consequently, subsidence due to underground mining or resource extraction is not likely to occur in the proposed LNG terminal. Karst terrain is discussed below. Acceptable settlement criteria for the storage tanks would be performed in the design phase based on site-specific geotechnical borings collected at the storage tank locations. Currently, the storage tanks are expected to be built on reinforced concrete mat foundations bearing directly on competent bedrock.

#### 4.1.4.3.3 Sendout Pipeline

There is no active underground mining or pumping of oil and gas from underground reserves or large groundwater withdrawals from large water supplies along the sendout pipeline route. Consequently, subsidence due to underground mining or resource extraction is not likely to occur along the proposed sendout pipeline. Karst terrain is discussed below.

#### 4.1.4.4 Karst Terrain

Karst terrain develops in areas that are underlain by carbonate rocks and evaporites. Weathering and erosion produce a high degree of rock solubility in karst topography. Characteristic landforms such as sinkholes and caves are formed from the dissolution of the rock. The potential for karst is greatest where surficial deposits are less than 30 feet in thickness and the underlying carbonate rocks occur at depths at or just above the water table. In some areas, karst features are known to exist at depths as great as 100 feet bgs. No karst terrain has been identified at the proposed Downeast LNG terminal site or along the pipeline route.

Even though the project would not be considered susceptible to karst features and underground subsidence impacts, the project facilities would be designed and constructed to meet or exceed the federal safety standards set forth in 49 CFR Part 192. This would ensure integrity of the project facilities and minimize the potential for any pipe failures due to ground subsidence. Additionally, Downeast would conduct regular patrols of the sendout pipeline right-of-way during operations to identify conditions, including any areas of ground subsidence that might affect the safety or operation of the pipeline. Strict adherence to these standards and procedures would minimize the potential for any risk to the project posed by ground subsidence.

#### 4.1.4.5 Landslides

A landslide is the perceptible downward sliding of soil, rock or a mixture of the two (American Geological Institute 1976) and can include a wide range of ground movement, such as rock falls, deep failure of slopes, and shallow debris flows. Although gravity's action on an over-steepened slope is the primary reason for a landslide, there are other contributing factors affecting the original slope stability (Wikipedia 2007).

##### 4.1.4.5.1 Waterway for LNG Marine Traffic

Slides, flows, and falls are not anticipated to be of concern along the waterway for LNG marine traffic because these phenomena are mainly associated with steep slopes. This area is not considered to be susceptible to landslides. No significant impacts from landslides would be expected along the waterway for LNG marine traffic.

##### 4.1.4.5.2 LNG Terminal

Slides, flows, and falls are not anticipated to be of concern to the proposed terminal because these phenomena are mainly associated with steep slopes. Slopes in the vicinity of the tanks are currently envisioned to be constructed no steeper than a 1.5H:1V. Based on the characteristics of the subsurface materials relative to landside potential, analysis of the 1.5H:1V slope indicates that this angle of repose would be stable. The LNG storage tanks are being designed to sit on concrete mats directly overlying competent bedrock and thus, would be stable. Therefore, the LNG terminal site is not considered to be susceptible to landslides.

##### 4.1.4.5.3 Sendout Pipeline

Slides, flows, and falls are not anticipated to be of concern to the proposed sendout pipeline because these phenomena are mainly associated with steep slopes. The sendout pipeline route is not considered to be susceptible to landslides.

### 4.1.5 Flooding and Storm Surge

#### 4.1.5.1 Waterway for LNG Marine Traffic

No tsunamis have been recorded in the Bay of Fundy or Passamaquoddy Bay (Whitford 2007), and the potential for a damaging tsunami to occur along the North Atlantic coast of New England is minimal for several reasons. The plate tectonic mechanisms associated with tsunami development in the Pacific are not present in the North Atlantic (Lander 1989; Slovinsky 2005). The continental shelf located off New England creates shallower waters that would dissipate the wave energy in a tsunami (Lander 1989). Moreover, the shallow waters off George's Bank would likely reflect any tsunami-like wave back into the North Atlantic or break up the wave (Slovinsky 2005). The West Isles (including Campobello and Deer Island) also provide physical obstacles to large waves transiting out of the North Atlantic into the Bay of Fundy.

Flooding is not an issue along the waterway for LNG marine traffic as the area is tidally influenced and is by definition underwater. The long-term tidal record for Eastport was digitized and analyzed to estimate storm surge levels. The calculated extreme surge levels are only slightly higher than the highest astronomical tide levels and are calculated to be 4.04 feet above the highest recorded mean high water level. No significant impacts from flooding would be expected along the waterway for LNG marine traffic.

#### 4.1.5.2 LNG Terminal

The land-side portion of the terminal area is outside both the 100-year and 500-year flood zones (Federal Emergency Management Agency [FEMA] 2006). The trestle abutment and pier structures would be located within the 100-year flood zone. The long-term tidal record was digitized and analyzed to estimate storm surge levels within the 100-year flood zone. The calculated extreme surge levels are only slightly higher than the highest astronomical tide levels and are calculated to be 4.04 feet above the highest recorded mean high water level at the site. All structures at the site would be built in accordance with applicable state and federal building codes to prevent or minimize damage from these flood events at the stated surge levels.

Several commenters raised the question of long-term sea level rise since the last Ice Age or as a consequence of global warming. Depending on the rate of input of carbon dioxide, global climate models predict a change in sea level by the year 2100 between 1.6 and 11.5 feet above present levels. Most scientists accept the lower to mid-lower range of predicted levels (Kelley et al. 2005). The Intergovernmental Panel on Climate Change cites a prediction of 1.6-foot increase (Slovinsky and Dickson 2006) and the state of Maine is using a 2-foot increase in sea level over the next 100 years for unconsolidated materials in coastal dune projects (Slovinsky and Dickson 2006). The bedrock found at the LNG terminal site is more resistant to coastal erosion processes and wave action compared to unconsolidated materials found in dune systems. The current high water tide level is approximately 10 feet (NAVD 88) and the shoreline along the site is a vertical bluff approximately 20 feet above the high water line. All of the storage terminal structures would be located above elevation 50 feet. The lowest point of the pier is at the shoreline abutment, which is 9.2 feet above mean high water; therefore, the projected 2-foot rise would have no impact on any of the LNG terminal structures.

### 4.1.5.3 Sendout Pipeline

Flash flooding is possible at stream crossings along the sendout pipeline. The sendout pipeline route would cross over FEMA's 100-year flood zone in 14 locations and the 500-year flood zone in two additional locations (see table 4.1.5.3-1). Executive Order 11988 requires federal agencies to avoid to the extent possible the long and short-term adverse impacts associated with the occupancy and modification of flood plains and to avoid direct and indirect support of floodplain development wherever there is a practicable alternative. Because of its linear nature and defined starting and ending points, it is not possible for the Downeast sendout pipeline to entirely avoid crossing floodplains. However, because floodplains are associated with waterbodies and wetlands, Downeast has generally attempted to avoid crossings, and where unavoidable minimize the crossing length of floodplains to the extent possible. Where floodplains must be crossed, the pipeline would be installed below the ground surface, and the surface of the right-of-way restored and stabilized following construction which would minimize environmental impacts and modification of floodplains. The pipeline siting process and proposed measures to minimize environmental impacts and modification of floodplains that are crossed would meet the intent of Executive Order 11988.

The pipeline crossings of streams and rivers would be designed and protected to mitigate against damage due to high velocity flows and potential erosion due to seasonal and flash flooding.

TABLE 4.1.5.3-1

**Flood Zone Determinations Along the Sendout Pipeline**

| Distance (mile) | Milepost From | Milepost To | Community | Designation |
|---|---|---|---|---|
| 0.01 | 6.69 | 6.70 | City of Calais | 100-Year Floodplain |
| 0.04 | 7.63 | 7.67 | City of Calais | 100-Year Floodplain |
| 0.02 | 8.61 | 8.63 | City of Calais | 100-Year Floodplain |
| 0.09 | 13.76 | 13.85 | City of Calais | 500-Year Floodplain |
| 1.33 | 13.85 | 15.18 | City of Calais | 100-Year Floodplain |
| 0.07 | 15.92 | 15.99 | Baring Pit | 100-Year Floodplain |
| 0.08 | 16.04 | 16.12 | Baring Pit | 100-Year Floodplain |
| 0.53 | 16.15 | 16.69 | Baring Pit | 100-Year Floodplain |
| 0.17 | 16.88 | 17.05 | Baring Pit | 100-Year Floodplain |
| 0.44 | 17.75 | 18.19 | Baring Pit/Town of Baileyville | 100-Year Floodplain |
| 0.19 | 18.28 | 18.47 | Town of Baileyville | 100-Year Floodplain |
| 0.02 | 21.30 | 21.32 | Town of Baileyville | 100-Year Floodplain |
| 0.14 | 22.42 | 22.56 | Town of Baileyville | 100-Year Floodplain |
| 0.15 | 23.20 | 23.36 | Town of Baileyville | 500-Year Floodplain |
| 0.28 | 28.33 | 28.61 | Town of Baileyville | 100-Year Floodplain |
| 0.12 | 28.70 | 28.82 | Town of Baileyville | 100-Year Floodplain |

Source: Maine Office of GIS 1997.

## 4.2 SOILS AND SEDIMENTS

### 4.2.1 Soil Composition and Limitations

#### 4.2.1.1 LNG Terminal

The offshore portion of the LNG terminal is primarily underlain by river bottom sands and silts close to shore and shallow marine clays farther from shore. The shoreline of the LNG terminal site consists of an approximately 20-foot-high "bluff" feature (near-vertical outcropping of bedrock). This feature extends from approximately 30 feet above mean sea level (MSL) down to about 10 feet above MSL, which corresponds to the estimated mean high water tide level at the site. The rocky shoreline at the LNG terminal is generally consistent with the steep, rocky shorelines common along the waterway for LNG marine traffic, as well as other portions of Mill Cove.

The 80-acre parcel of land on which the Downeast LNG terminal would be located is underlain by three primary soil types: Lamoine-Buxton Complex, derived from glaciomarine or glaciolacustrine deposits; Creasey-Abram Complex, derived from glacial till deposits; and Lamoine-Creasey-Scantic Complex, derived from glaciomarine, glaciolacustrine, or glacial till deposits. Construction and operation of the proposed LNG terminal would require about 47 acres of land, located primarily on the southern portion of this parcel. The soils occurring within the footprint of the proposed terminal include only Creasey-Abram Complex and Lamoine-Creasey-Scantic Complex. The soil types associated with the storage tanks are Lamoine-Creasey-Scantic and Creasey-Abram; both storage tanks are predominately located within the Lamoine-Creasey-Scantic Complex. The administration building and its parking lot, control building, maintenance building and its parking lot, compressor/blower building, LNG vaporizer, and the spill containment basin are all located within the Lamoine-Creasey-Scantic Complex. The LNG transfer area, spill containment basin, and the trestle abutment structure are all located within the Creasey-Abram Complex. The remaining 33 acres of the 80-acre parcel of land, which include areas underlain by the Lamoine-Buxton Complex, would remain undisturbed. Table 4.2.1.1-1 provides a summary of soil characteristics and limitations associated with the LNG terminal footprint and off-site temporary terminal laydown areas.

TABLE 4.2.1.1-1

**Soil Types and Associated Limitations for the Downeast LNG Terminal and Associated Laydown Yards**

| Soil Type | Acres Affected | Drainage Classification | Farmland of Statewide Importance | Hydric Soil | Revegetation Potential (Grass / Herbaceous) | High Compaction Potential | High Erosion Potential |
|---|---|---|---|---|---|---|---|
| **LNG Terminal** | | | | | | | |
| Creasey-Abram Complex | 19.7 | Somewhat Excessively Drained | No | No | Fair | No | Yes |
| Lamoine-Creasey-Scantic Complex | 26.9 | Excessively Drained to Poorly Drained | Yes | Yes | Good | Yes | No |
| **Laydown Yards** | | | | | | | |
| Laydown Yard A | | | | | | | |
| Hermon-Monadnock-Skerry Complex | 3.2 | Somewhat Excessively Drained | No | No | Poor/Good | No | Yes |

| TABLE 4.2.1.1-1<br>Soil Types and Associated Limitations for the Downeast LNG Terminal and Associated Laydown Yards | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Soil Type** | **Acres Affected** | **Drainage Classification** | **Farmland of Statewide Importance** | **Hydric Soil** | **Revegetation Potential (Grass / Herbaceous)** | **High Compaction Potential** | **High Erosion Potential** |
| Laydown Yard B | | | | | | | |
| Lamoine-Creasey-Scantic Complex | 2.2 | Excessively Drained to Poorly Drained | Yes | Yes | Good | Yes | No |
| Laydown Yard C | | | | | | | |
| Lamoine-Creasey-Scantic Complex | 3.2 | Excessively Drained to Poorly Drained | Yes | Yes | Good | Yes | No |

Note: No prime farmland located at the Downeast LNG terminal.

#### 4.2.1.2 Sendout Pipeline

Over 50 soil types would be crossed by the proposed sendout pipeline and associated pipeline components, the majority of which are derived from glacial till material with areas of glaciomarine, glaciofluvial, and glaciolacustrine material interspersed. The soil types that would be affected by the proposed sendout pipeline, the aboveground facilities, and their associated soil limitations are listed in Appendix L.

Soil limitations identified along the proposed sendout pipeline route include shallow bedrock, hydric soils, poor revegetation potential (for herbaceous plants and grasses), high compaction potential, prime farmland (classified by the USDA NRCS), farmland of statewide importance (classified by the USDA NRCS), and high erosion potential. Table 4.2.1.2-1 provides the acreages of temporary and permanent impacts associated with each type of pipeline component on the various identified soil limitations. These data are also provided as percentages of the total area temporarily (258.6 acres) and permanently (141.5 acres) affected by the sendout pipeline and components.

Of the various pipeline components, only the one new access road (at MP 15.4), and one MLV site (at MP 17.17) are expected to cause permanent disturbances to soil and sediments. Although four new access roads would be associated with the sendout pipeline, three of these roads have existing road bases on which off-road vehicle access has been established for years. These roads overlay soil types that have been disturbed by additions of gravel and the compaction or removal of the native soil cover. Consequently, the bases for these roads do not fit into the standard soil classification; therefore, the upgrade of the road bases would not affect native soils and sediments either temporarily or permanently, except in areas where widening of the road bases may occur. The fourth access road, located at MP 15.4, would require clearing and grading for a new road base; therefore, it would have both temporary and permanent impacts on soil, including compaction.

TABLE 4.2.1.2-1

**Summary of Soil Limitations Along the Proposed Sendout Pipeline and Pipeline Components**

| **Pipeline Component** | **Impact Type** | **Shallow Bedrock (< 60" bgs) e/** | **Hydric Soil** | **Very Poor or Poor Revegetation Potential for Herbaceous f/** | **Very Poor or Poor Revegetation Potential for Grass g/** | **High Compaction Potential h/** | **Prime Farmland** | **Farmland of Statewide Importance** | **High or Potentially High Erosion Potential** |
|---|---|---|---|---|---|---|---|---|---|
| | | | | **Acres of Impact** | | | | | |
| Pipeline | Temporary a/ | 67.4 | 65.88 | 8.83 | 148 | 89.26 | 7.24 | 38.89 | 115.51 |
| | Permanent b/ | 43.85 | 39.95 | 5.24 | 95.2 | 54.6 | 4.38 | 23.86 | 75.19 |
| ATWS | Temporary a/ | 2.93 | 4.49 | 0.48 | 6.74 | 5.6 | 0.27 | 3.47 | 5.44 |
| | Permanent b/ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ATWS HDD Pad | Temporary a/ | 1.58 | 1.41 | 0.11 | 3.3 | 3.59 | 0.32 | 3.58 | 3.95 |
| | Permanent b/ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Laydown Area | Temporary a/ | 5.04 | 4.98 | 0.8 | 10.39 | 9.16 | 0 | 8.65 | 9.71 |
| | Permanent b/ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| New Access Road i/ | Temporary a/ | 0 | 0.07 | 0 | 0 | 0.3 | 0 | 0.53 | 0.23 |
| | Permanent b/ | 0 | 0.07 | 0 | 0 | 0.3 | 0 | 0.53 | 0.23 |
| Pipe Storage Area | Temporary a/ | 0 | 1.95 | 0 | 0 | 1.95 | 0 | 2.95 | 1.5 |
| | Permanent b/ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Valve Site j/ | Temporary a/ | 0.3 | 0 | 0 | 0 | 0 | 0.3 | 0 | 0 |
| | Permanent b/ | 0.4 | 0 | 0 | 0 | 0 | 0.4 | 0 | 0 |
| **All Components** | Temporary a/ | 77.25 | 78.78 | 10.22 | 168.43 | 109.86 | 8.13 | 58.07 | 136.34 |
| | Permanent b/ | 44.25 | 40.02 | 5.24 | 95.2 | 54.9 | 4.78 | 24.39 | 75.42 |
| | | | | **Percentage of Total Pipeline Impacts** | | | | | |
| Pipeline | Temporary c/ | 26% | 25% | 3% | 57% | 35% | 3% | 15% | 45% |
| | Permanent d/ | 31% | 28% | 4% | 67% | 39% | 3% | 17% | 53% |
| ATWS | Temporary c/ | 1% | 2% | 0% | 3% | 2% | 0% | 1% | 2% |
| | Permanent d/ | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| HDD ATWS | Temporary c/ | 1% | 1% | 0% | 1% | 1% | 0% | 1% | 2% |
| | Permanent d/ | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Laydown Area | Temporary c/ | 2% | 2% | 0% | 4% | 4% | 0% | 3% | 4% |
| | Permanent d/ | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

TABLE 4.2.1.2-1

**Summary of Soil Limitations Along the Proposed Sendout Pipeline and Pipeline Components**

| Pipeline Component | Impact Type | Shallow Bedrock (< 60" bgs) e/ | Hydric Soil | Very Poor or Poor Revegetation Potential for Herbaceous f/ | Very Poor or Poor Revegetation Potential for Grass g/ | High Compaction Potential h/ | Prime Farmland | Farmland of Statewide Importance | High or Potentially High Erosion Potential |
|---|---|---|---|---|---|---|---|---|---|
| New Access Road i/ | Temporary c/ | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | Permanent d/ | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Pipe Storage Area | Temporary c/ | 0% | 1% | 0% | 0% | 1% | 0% | 1% | 1% |
| | Permanent d/ | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Valve Site j/ | Temporary c/ | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | Permanent d/ | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **All Components** | Temporary c/ | 30% | 30% | 4% | 65% | 42% | 3% | 22% | 53% |
| | Permanent d/ | 31% | 28% | 4% | 67% | 39% | 3% | 17% | 53% |

a/ Temporary area includes cleared areas of the construction right-of-way and aboveground facilities that would be cleared during the construction of the project.
b/ Permanent area is a subset of Temporary area, and includes only those areas that will be permanently maintained for project operations.
c/ Temporary impacts percentage based on total temporary impacts of pipeline and pipeline components of 258.6 acres.
d/ Permanent impacts percentage based on total permanent impacts of pipeline and pipeline components of 141.5 acres.
e/ Shallow Bedrock areas do not include areas underlain by soils with unknown depth to bedrock.
f/ Very Poor or Poor Revegetation Potential for Herbaceous areas do not include areas underlain by soils with unknown revegetation potential for herbaceous or soils for which this limitation is not applicable.
g/ Very Poor or Poor Revegetation Potential for Grass areas do not include areas underlain by soils with unknown revegetation potential for grass or soils for which this limitation is not applicable.
h/ High Compaction Potential areas do not include areas underlain by soils with unknown compaction potential.
i/ Only the access road at MP 15.4 would be a newly created access road. All other access roads overlay disturbed soil types for which off-road vehicle access has been established for years. Although upgrade of these road bases may be required, the underlying soil types have been disturbed by additions of gravel and removal of the native soil cover and therefore do not fit into the standard soil classification. Upgrade of the road bases would not impact native soils and sediments either temporarily or permanently, except for in areas where widening of the road bases may occur.
j/ Only the valve site located at MP 17.17 of the sendout pipeline is accounted for in this table. Neither of the other two valve sites are located along the sendout pipeline: one is located within the footprint of the LNG terminal and the other is located within the footprint of the Baileyville Compressor Station. The valve site at MP 17.2 has a total area of 0.5 acres; however, 0.2 acres of the site overlap the temporary pipeline right-of-way, and 0.1 acres overlap the permanent pipeline right-of-way. Because the impacts of these overlapping areas are already accounted for in the right-of-way areas of impact, they are omitted from the valve site impacts.

Source: USDA 2006a.

Of the three MLV sites associated with the project, only one would be located along the sendout pipeline (at MP 17.17). A valve station and pig receiving facility would be constructed at the site of the Baileyville Compressor Station. The other valve site and pig launching facility would be located within the footprint of the LNG terminal. The valve site at MP 17.17 would have a total permanent area of 0.5 acre; however, 0.2 acre of the site would overlap the temporary pipeline right-of-way, and 0.1 acre would overlap the permanent pipeline right-of-way. Because these overlapping areas are already accounted for in the right-of-way impacts, they are omitted from the valve site impacts. The valve station and pig receiving facility at MP 29.8 would affect 0.5 acre during construction and 0.3 acre during operation. The compressor site is a disturbed area; consequently, the soils that would underlie the site do not fit into the standard soil classification. Therefore, the valve station and pigging facility would not impact any soils that are in an undisturbed, native condition. All other pipeline components would be temporary areas associated with construction of the project and would not be expected to cause permanent disturbances.

To minimize or avoid adverse effects to soils, Downeast would adhere to the measures contained in its Plan and *Soil Erosion and Sediment Control Guidelines*. In addition, Downeast would develop a project-specific Stormwater Pollution Prevention Plan (SWPPP) as required by the CWA. This SWPPP would include the protocol for erosion and sediment control procedures for the proposed Downeast LNG Project. These procedures would be considered the BMPs that are based on Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*. We believe that Downeast's use of these plans would meet the intent of the Maine Erosion and Sedimentation Control Law. Downeast would also be following the State of Maine's BMPs for erosion and sedimentation control during construction (Maine DEP 2013). These guidelines are designed to minimize any impact on agricultural, residential, and wetland soils. Construction measures include postponing soil disturbances when soils are excessively wet and separating the topsoil layer from the subsoils when grading and trenching. Downeast has adopted the *Soil Erosion and Sediment Control Guidelines* from M&NE, which describe approved seeding mixtures to be used in order to reseed the areas affected by the pipeline construction.

### 4.2.2 Prime Farmland

Prime farmland, as defined by the USDA, is "land that has the best combination of physical and chemical characteristics for producing food, feed, forage, fiber, and oilseed crops, and is also available for these uses (the land could be cropland, pastureland, rangeland, forest land, or other land, but not developed land or water). The soils are of the highest quality and can economically produce sustained high yields of crops when treated and managed according to acceptable farming methods" (USDA 2007a). Soils that do not meet this criteria may be considered prime farmland if the limiting factor is mitigated (e.g., using artificial drainage or irrigation). Prime farmland soils characteristically have adequate natural moisture content; a specific soil temperature range; pH between 4.5 and 8.4 in the rooting zone; low susceptibility to flooding; low risk to wind and water erosion; minimum permeability rates; and low rock fragment content (USDA 2007a). Prime farmland can include land that possesses the above characteristics but is being used currently to produce livestock or timber.

Soils that nearly meet the USDA prime farmland criteria may be designated "farmland of statewide importance." These are defined by the USDA as lands containing "nearly" prime farmland as determined by the state agency or agencies and contain similar criteria for classification as prime farmland.

#### 4.2.2.1 LNG Terminal

The soils at the proposed location of the terminal and the laydown yards are not designated prime farmland. However, there are 32.3 acres of soil within the LNG terminal footprint and the laydown yards that are designated farmland of statewide importance. This area is not currently used for agriculture. Approximately 26.9 acres would be permanently affected by occupation by the terminal facilities and the remaining 5.4 acres would be temporarily disturbed during construction for the laydown yards. The laydown yards would be a short-term impact mitigated in accordance with the Downeast Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*, and would not affect the potential use of farmland of statewide importance for future agricultural purposes. Specific mitigation measures may include topsoil segregation and decompaction. We believe the unavoidable conversion of 32.3 acres of farmland of statewide importance as a result of operation of the proposed terminal would not be a significant impact.

#### 4.2.2.2 Sendout Pipeline

The sendout pipeline right-of-way would temporarily affect approximately 7.24 acres of prime farmland and 38.89 acres of farmland of statewide importance, and would permanently affect approximately 4.38 acres of prime farmland and 23.86 acres of farmland of statewide importance. Additional temporary disturbances from pipeline construction would include approximately 0.27 acre of prime farmland and 3.47 acres of farmland of statewide importance for additional temporary workspace (ATWS); 0.32 acre of prime farmland and 3.58 acres of farmland of statewide importance for HDD ATWS; 8.65 acres of farmland of statewide importance for laydown areas; and 2.95 acres of farmland of statewide importance for pipe storage areas. The new access road at MP 15.4 would affect approximately 0.53 acre of farmland of statewide importance during construction and operation. The 0.5-acre valve site at MP 17.17 would affect approximately 0.3 acre of prime farmland during construction (0.2 acre would be affected by the construction right-of-way within the MLV footprint) and approximately 0.4 acre of prime farmland during operation (0.1 acre would be affected by the permanent right-of-way within the MLV footprint) (USDA 2006a).

The areas of prime farmland and farmland of statewide importance crossed by the sendout pipeline and pipeline components are not active agricultural areas. With the exception of the access road at MP 15.4 and the valve station at MP 17.17, most impacts would be short-term and would not affect the potential use of prime farmland for future agricultural purposes. The implementation of the Downeast Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* would serve to minimize any temporary impacts on prime farmland or farmland of statewide importance. Mitigation measures may include topsoil segregation, temporary erosion controls such as silt fence, staked hay or straw bales, and sand bags, as necessary, soil decompaction, and revegetation. The valve station along with the permanent pipeline right-of-way at MP 17.17 and the access road at MP 15.4 would remove 0.5 acre of prime farmland and 0.5 acre of farmland of statewide importance, respectively, from future agricultural use. Because this land is not actively farmed, we believe that the unavoidable conversion of farmland to developed land would not be a significant impact.

### 4.2.3 Hydric Soils

Hydric soils are defined as "soils that formed under conditions of saturation, flooding, or ponding long enough during the growing season to develop anaerobic conditions in the upper part" (USDA 2006b). These soils are typically associated with wetlands. Soils that are artificially drained or protected from flooding (e.g., by levees) are still considered hydric if the soil in its undisturbed state would meet the definition of a hydric soil.

#### 4.2.3.1 LNG Terminal

Approximately 26.9 acres of hydric soils are found within the footprint of the terminal site and 5.4 acres are found within the laydown yards. The area of hydric soil within the terminal footprint would be permanently affected by occupation by the terminal facilities. During construction of the project, loss of soil productivity due to compaction and damage to soil structure from heavy equipment are likely to occur. We believe the unavoidable conversion of 26.9 acres of hydric soils as a result of operation of the proposed terminal would not be a significant impact. Effects to hydric soils in the laydown yards would be temporary, and may be mitigated using methods such as dry season construction and decompaction during restoration. We believe that Downeast's implementation of these provisions, as well as the use of the Downeast Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* during construction and restoration would minimize impacts on hydric soils.

#### 4.2.3.2 Sendout Pipeline

Approximately 65.88 acres of hydric soils would be located in the temporary pipeline right-of-way, 39.95 acres of which also would be located in the permanent right-of-way. Areas of hydric soils affected during construction also would include approximately 4.49 acres of ATWS, 1.41 acres of HDD ATWS, 4.98 acres of laydown areas, and 1.95 acres of pipe storage areas. Approximately 0.07 acre of hydric soils would be affected by construction and operation of the new access road at MP 15.4. There would be no temporary or permanent impact on hydric soils by the valve site at MP 17.17 (USDA 2006a).

Hydric soils are generally poorly drained and would be expected to have high clay content with low permeability. These characteristics make hydric soils susceptible to compaction (as discussed below). Soils in residential and agricultural areas would be decompacted during restoration; therefore, land use would not be affected by soil compaction. In addition, high groundwater levels associated with hydric soils could create a buoyancy hazard for the pipeline. Special construction techniques, such as concrete coating and other weighting methods would be used to overcome buoyancy hazards during operation of the pipeline. Practices such as dry season construction and/or trench dewatering would typically be used. We believe that Downeast's implementation of these provisions, as well as the use of the Downeast Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* during construction would minimize impacts on hydric soils.

### 4.2.4 Erosion Potential

Erosion is a continuing natural process that can be accelerated by human disturbance. Variables that may influence erosion potential include soil characteristics, climate, topography, vegetative cover, soil texture, surface roughness, percent slope, and length of slope. Water erosion typically occurs on loose, exposed soils, with a low permeability, on moderate to steep slopes. Wind erosion generally occurs in an arid climate with soils containing little vegetative growth and high wind conditions.

Clearing, grading, and equipment movement over soils could accelerate the erosion process, and without adequate soil erosion BMPs, all construction practices could result in the discharge of eroded sediment to waterbodies and wetlands. Soil loss due to erosion could also reduce soil fertility and impair revegetation rates.

#### 4.2.4.1 LNG Terminal

The shoreline at the LNG terminal consists of a steep, rocky bluff that extends down to the estimated mean high water tide level. The presence of this feature prevents sand deposition, and the only beach environment at the site is intertidal in nature. The terminal shoreline is therefore not considered prone to erosion.

Of the approximately 47 acres of land within the proposed terminal footprint, approximately 19.7 acres of soil are classified as "potentially highly erodible." Approximately 3.2 acres within the laydown yards are classified as "potentially highly erodible" soils. Construction operations such as clearing and grading would increase soil erosion potential. Downeast would implement their project-specific SWPPP and their Plan and *Soil Erosion and Sediment Control Guidelines* to minimize erosion. Mitigation measures to minimize erosion include use of silt fence, slope breakers, and stormwater management controls.

The shoreline at the LNG terminal is primarily comprised of rocky material and is not prone to erosion. Erosion of the shoreline at the LNG terminal is not expected to occur from vessel docking, as the vessels would be operating at low speeds during docking.

#### 4.2.4.2 Sendout Pipeline

Along the sendout pipeline temporary right-of-way, approximately 115.51 acres of soils would have a high or potentially high erosion potential; the permanent right-of-way would have approximately 75.19 acres of soils with a high or potentially high erosion potential. Other temporary pipeline construction areas underlain by soils with a high or potentially high erosion hazard would include 5.44 acres of ATWS, 3.95 acres of HDD ATWS, 9.71 acres of laydown areas, and 1.5 acres of pipe storage areas. Construction and operation of the new access road at MP 15.4 would impact approximately 0.23 acre of soil with high or potentially high erosion potential. The valve site at MP 17.17 would not include any soils with this limitation (USDA 2006a).

Because Downeast would implement its Plan and *Soil Erosion and Sediment Control Guidelines* for erosion and sedimentation control during construction, the adverse impacts from erosion would be minimal. During pipeline construction, Downeast would use erosion control structures and erosion control fabrics (as outlined in the Downeast Plan and *Soil Erosion and Sediment*

*Control Guidelines*). The erosion control measures include the installation of slope breakers and sediment barriers such as silt fencing and hay bales, the use of mulch and erosion control fabrics, and restoration within 20 days of backfilling the trench. We conclude that implementation of these measures would minimize overall soil erosion that could result from construction of the project.

### 4.2.5 Revegetation Potential

Successful restoration and revegetation in areas that are temporarily disturbed during construction are important to maintain ecosystem productivity and to protect underlying soil from potential damage, such as erosion. Soils that have a potential for poor (or very poor) revegetation were determined by the USDA NRCS. The revegetation potential of each major soil type was rated according to its potential for producing domestic perennial grasses and herbaceous legumes. Soil properties that affect the growth of grasses and legumes include the topsoil thickness for the root zone, texture of the surface layer, available water capacity, wetness, surface stoniness, flood hazard, soil temperature, and slope. Examples of grasses and legumes are fescue, lovegrass, broomgrass, clover, alfalfa, bluegrass, switchgrass, timothy, and trefoil, all of which are typical varieties used for revegetation of disturbed areas.

#### 4.2.5.1 LNG Terminal

All of the soils found at the terminal location are considered to have "good" to "fair" revegetation potential. The terminal land-based facilities will occupy approximately 47 acres during operation; this land will not be available for revegetation during the lifetime of the facility. Downeast would implement the requirements in its Plan and *Soil Erosion and Sediment Control Guidelines* for revegetation of disturbed areas outside the footprint of the project facilities, which include approximately 8.0 acres of laydown areas. These requirements include:

- fertilize and add soil pH modifiers in accordance with written recommendations obtained from the local soil conservation authority;
- prepare a seedbed in disturbed areas to a depth of 3 to 4 inches using appropriate equipment to provide a firm seedbed; and
- seed disturbed areas in accordance with written recommendations for seed mixes, rates, and dates obtained from the local soil conservation authority or as requested by the landowner or land management agency.

Downeast would revegetate and restore disturbed areas using seed mixtures recommended by the NRCS. We conclude that if revegetation is conducted in accordance with these measures, areas disturbed by construction would be successfully revegetated. See section 4.4.2 of this EIS for further information on revegetation.

#### 4.2.5.2 Sendout Pipeline

The temporary pipeline right-of-way would include approximately 8.83 acres of soils that are classified as having very poor or poor revegetation potential for herbaceous plants and approximately 148 acres of soils that are classified as having very poor or poor revegetation potential for grasses. The permanent pipeline right-of-way would include approximately 5.24 acres of soils with very poor or poor revegetation potential for herbaceous plants and

95.2 acres of soils with very poor or poor revegetation potential for grasses. Areas of soils with very poor or poor revegetation potential for herbaceous plants affected by temporary pipeline components would include approximately 0.48 acre of ATWS, 0.11 acre of HDD ATWS, and 0.8 acre of laydown areas. Areas of soils with very poor or poor revegetation potential for grasses affected by temporary pipeline components would include approximately 6.74 acres of ATWS, 3.3 acres of HDD ATWS, and 10.39 acres of laydown areas. No areas with very poor or poor revegetation potential for either grasses or herbaceous plants would be located at pipe storage areas, the new access road at MP 15.4, or the valve site at MP 17.17 (USDA 2006a).

Downeast would implement the requirements in its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* for revegetation of disturbed areas along the proposed sendout pipeline route. Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* describe approved seeding mixtures to be used to reseed areas affected by pipeline construction. All construction work areas would be monitored for the success of revegetation and restoration. Inspections would be conducted after regrading, stabilization, and reseeding; at the beginning and latter parts of the first full growing season; and during the following four growing seasons. We conclude that if revegetation is conducted in accordance with the mitigation measures described in Downeast's Plan and *Soil Erosion and Sediment Control Guidelines*, areas disturbed by construction along the sendout pipeline would be successfully revegetated.

### 4.2.6 Compaction Potential

Soil compaction modifies the structure and reduces the porosity and moisture-holding capacity of the soil. The degree of soil compaction during construction is dependent on moisture content and soil texture. Fine-textured soils with poor internal drainage are the most susceptible to compaction. Soils within the project areas were rated with high compaction potential values based on the following criteria:

- the soil has a surface horizon or soil texture of sandy, clay loam or finer;
- glaciomarine or glaciolacustrine parent materials; and
- drainage classifications of very poorly to somewhat poorly drained.

Construction equipment traveling over wet soils could lead to compaction of the soil structure, reduce pore space, increase runoff potential, and cause rutting. Compaction and rutting impacts would be more likely to occur when soils are moist or saturated.

#### 4.2.6.1 LNG Terminal

The Lamoine-Creasey-Scantic soils found at the terminal location are susceptible to compaction. This soil, comprising approximately 26.9 acres of the proposed site and 5.4 acres within laydown yards B and C, has glaciomarine or glaciolacustrine parent materials and is excessively drained to poorly drained. During construction of the project, loss of soil productivity due to compaction and damage to soil structure from heavy equipment are likely to occur. Wet periods during construction may also increase the potential for soil structural damage and compaction. These impacts would be minimal given that the site would be highly developed. Impacts on areas within the laydown yards would be minimized using methods such segregating topsoil, postponing soil disturbances when soils are excessively wet, and decompaction during restoration. These areas would be restored using the seeding and fertilizing requirements of Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*.

#### 4.2.6.2 Sendout Pipeline

The temporary right-of-way for the sendout pipeline would include approximately 89.26 acres of soils with high compaction potential, and the permanent right-of-way would include approximately 54.6 acres of soils with high compaction potential. Temporary construction areas underlain by soils with high compaction potential would consist of 5.6 acres of ATWS, 3.59 acres of HDD ATWS, 9.16 acres of laydown areas, and 1.95 acres of pipe storage areas. The new access road at MP 15.4 would include 0.3 acre of high compaction potential soils, all of which would be affected during both construction and operation. The new valve site at MP 17.17 would not include any soils with high compaction potential (USDA 2006a).

As stated in Downeast’s Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*, compaction would be mitigated in residential and any agricultural areas crossed by the project. Downeast would consult with landowners regarding adequate mitigation and restoration measures for decompaction. Mitigation for soil compaction would include segregating topsoil, postponing soil disturbances when soils are excessively wet, and using deep tillage operations during right-of-way restoration using a paraplow or similar implement. We believe that use of these measures during construction would minimize soil compaction resulting from construction of the proposed project.

### 4.2.7 Contaminated Soils

Existing contaminated soils located within or in close proximity to areas proposed for construction and operation of the Downeast LNG terminal and pipeline present potential hazards to both the environment and human health. A review of existing federal and state databases was conducted to identify known hazardous waste sites that could be sources of soil contamination near the various project components.

In addition to existing contaminated soils, contamination from spills or leaks of fuels, lubricants, and coolant from construction equipment for the Downeast LNG Project could adversely affect soils. Downeast has prepared an SPCC Plan template that describes spill prevention techniques, spill handling and emergency notification procedures, and training requirements. Construction contractors would be required to develop project-specific plans based on Downeast’s template prior to construction in order to minimize potential contamination of soil resources from accidental spills of hazardous materials. We have reviewed the template and find it adequate.

#### 4.2.7.1 LNG Terminal

EPA and Maine DEP records were searched to identify known contaminated soils within 0.5 mile of the project. Based on the results of the database query, no sites associated with hazardous materials or solid wastes were identified within 0.5 mile of the terminal site.

In order to minimize potential contamination of soil resources from accidental spills of hazardous materials during construction or operation of the LNG terminal, project-specific SPCC Plans based on Downeast’s SPCC Plan template would be prepared by construction contractors. These plans would provide detailed mitigation measures, including spill prevention techniques, spill handling, emergency notification procedures, and training requirements.

### 4.2.7.2 Sendout Pipeline

Along the sendout pipeline route, 16 records associated with the storage, potential release, or disposal of petroleum products or hazardous materials identified 13 sites that are located between 0.25 and 0.5 mile from the pipeline centerline. An additional 15 records identified 15 sites within 0.25 mile of the pipeline centerline (see tables 4.2.7.2-1 and 4.2.7.2-2). There are no sites located within the sendout pipeline construction right-of-way. However, C and S Auto Body located on U.S. Route 1 in Princeton at MP 26.9 is within 500 feet of the sendout pipeline temporary right-of-way. This site is listed in table 4.2.7.2-1 as a Maine DEP Recordable Potential Affected Soils Area.

TABLE 4.2.7.2-1

**EPA Recordable Potential Affected Soils Areas Within 0.25 and 0.50 Mile of the Sendout Pipeline Route Centerline**

| EPA ID | EDR Site Name a/ | Address | Town | Approximate Milepost | Sites Within 0.25 to 0.50 Mile | Sites Within 0.25 Mile |
|---|---|---|---|---|---|---|
| **RCRA – Small Quantity Generators** | | | | | | |
| S105404012 | Irving Baileyville Big Stop b/ | Houlton Road | Baileyville | 18.1 | X | |
| **Leaking Underground Storage Tanks** | | | | | | |
| S106792973 | Engroff Residence | Broadway | Baileyville | 18.4 | X | |
| S105404012 | Irving Baileyville Big Stop b/ | Houlton Road | Baileyville | 18.1 | X | |
| S104996501 | Irving Big Stop | Route 1 | Baileyville | 20.9 | | X |
| **Registered Underground Storage Tanks** | | | | | | |
| U003100743 | U.S. Post Office | Route 1 | Woodland | 18.7 | | X |
| S105404012 | Irving Baileyville Big Stop b/ | Houlton Road | Baileyville | 18.1 | X | |
| U002165581 | Dead River Co. | Middle Road | Baileyville | 18.8 | | X |
| U003099264 | Bohanons Inc. | Routes 1 & 9 | Baileyville | 18.1 | | X |
| **Leaking Aboveground Storage Tanks** | | | | | | |
| S106073293 | Samantha Reynolds | Route 1 | Baileyville | 21.9 | | X |
| S105111815 | Harold Grant | Washington Street | Baileyville | 18.8 | X | |
| S106403855 | Tanya Osnoe | Houlton Road | Baileyville | 18.7 | | X |
| S105002714 | Pat Dow | Main Street | Baileyville | 17.9 | X | |
| S105794268 | Emma Hodgkins | Maple Street | Baileyville | 18.2 | | X |
| **ME Spills** | | | | | | |
| S105404012 | Irving Baileyville Big Stop b/ | Houlton Road | Baileyville | 18.1 | X | |

a/ Environmental Data Resources, Inc.
b/ All four of these records are assumed to be located at the same site.
Source: EDR 2006.

Downeast would implement a screening program during construction to identify unanticipated areas of potentially contaminated soil and groundwater. In the event that impacted soils are encountered, Downeast would notify the Maine DEP to assess necessary remedial actions, and to implement necessary worker health and safety considerations during construction.

In order to minimize potential contamination of soil resources from accidental spills of hazardous materials during construction of the sendout pipeline, project-specific SPCC Plans based on Downeast's SPCC Plan template would be prepared by construction contractors. These plans would provide detailed mitigation measures, including spill prevention techniques, spill handling, emergency notification procedures, and training requirements.

TABLE 4.2.7.2-2

**Maine DEP Recordable Potential Affected Soils Areas Within 0.25 and 0.50 Mile of the Sendout Pipeline Route Centerline**

| EGAD Reference Number a/ | EGAD Site Name | Address | Town | Approximate Milepost | Sites Within 0.25 to 0.50 Mile | Sites Within 0.25 Mile |
|---|---|---|---|---|---|---|
| 28978 | Webster Country Store | Route 1 & Ridge Road | Robbinston | 0.6 | | X |
| 29682 | Baring Plt Dump | Old Route 1 | Baring | 17.2 | X | |
| 27274 | Baring Cemetery Assn | Cemetery Road | Baring | 17.3 | X | |
| 38243 | Woodland Irving Mainway | 32 Houlton Road | Baileyville | 17.9 | | X |
| 28912 | Don Scott | Route 9 | Baileyville | 18.0 | X | |
| 36461 | Moores Auto Body | Route 1 | Baileyville | 18.8 | X | |
| 27272 | Baileyville Town Site | Off Route 1 | Baileyville | 20.4 | | X |
| 32754 | Secondary Lagoons | Dump Road | Baileyville | 20.5 | X | |
| 36462 | Exxon Woodland | Route 1 | Baileyville | 20.6 | | X |
| 30782 | Baileyville C&D Site | Town Road | Baileyville | 20.7 | | X |
| 27271 | Baileyville DOT | Route 1 | Baileyville | 20.8 | X | |
| 36463 | VL Tammaro Oil Co Inc. | 647 Route 1 | Baileyville | 21.6 | | X |
| 27270 | Baileyville Dicenzo Site | Route 1 | Baileyville | 20.8 | X | |
| 36106 | Bohanons Exxon | Route 1 | Woodland | 21.9 | | X |
| 32060 | Scottway Oil | Mtn. View Drive | Baileyville | 23.2 | X | |
| 48501 | Monan Pit | Route 1 | Baileyville | 25.7 | X | |
| 36464 | C and S Auto Body | Route 1 | Princeton | 26.9 | | X |

a/ Maine DEP, Bureau of Land and Water Quality, Environmental and Groundwater Analysis Database.
Source: Maine DEP 2006a.

### 4.2.8 Contaminated Sediments

To determine if contaminated sediments are present in the area of the proposed pier, Downeast conducted a sediment sampling and analysis. Subtidal and intertidal sediments were sampled at 13 locations within the area. The 13 sediment samples (including one duplicate) were collected from 12 site locations in and adjacent to Mill Cove. Sediment samples collected were analyzed for semivolatile polyaromatic hydrocarbons (PAHs), organics, total metals, and inorganics (polychlorinated dibenzo-p-dioxins [PCDDs or dioxins] and polychlorinated dibenzofurans [PCDFs or furans]). The chemical analyses of sediment were conducted following the Regional Implementation Manual for the Evaluation of Dredged Material Proposed for Disposal in New England Waters.

The analytical results of the sediment analyses were compared to the NOAA Fisheries Screening Quick Reference Tables for marine sediment. The comparison standards are established for potential effects to biological organisms. Although the laboratory's detection limits were higher than the most conservative screening criteria, several semivolatile organic compounds (SVOCs) were detected with concentrations no higher than 150 micrograms per kilogram (µg/kg), or parts per billion.

Metals analyses determined that arsenic and nickel also exceeded the most conservative biological screening levels, and cobalt, manganese, and selenium concentrations exceeded slightly higher benchmarks. One dioxin and one furan compound were also detected, but concentrations were estimated lower than the lower calibration limit.

Downeast conducted a geotechnical investigation of Passamaquoddy Bay along the proposed pier footprint in June and July 2006. Six borings were completed. In the two borings closest to shore, samples for chemical analysis were collected. These samples were composites from depths of 0 to 7 feet (1 boring), and 0 to 6 feet and 8 to 14 feet (1 boring) below the bay bottom. Analyses performed were for polychlorinated biphenyls (PCBs), pesticides, semivolatile PAHs, and RCRA metals. PCBs, pesticides, and PAHs were not detected in any samples. Maximum total metals results were (in µg/kg): arsenic (4.4), cadmium (non-detect), chromium (21), copper (8.9), mercury (0.014), nickel (19), lead (8.9), and zinc (35).

No dredging activity is proposed as part of the terminal construction process. Sediments may be disturbed during the installation of the pier pilings and due to propeller wash; however, the redistribution would be local and minor. Propeller wash due to normal operation of tugs and escort vessels would not be expected to increase turbidity in Passamaquoddy Bay because the sediments in this area appear to be cohesive, soft marine clays and because the depth of water at the pier along with the timing of LNG vessel and tug arrivals and departures at high tide would minimize the disturbance of the sediments.

Some low-level sediment contamination was identified in the general area of the proposed pier construction activities. Downeast is not proposing to perform any dredging, trenching, or substrate-disturbing activity other than pile installation. In order to minimize the amount of sediment released into the water column, pile installation would be performed using a vibrohammer. Near shore, in the area of the proposed pier, this method would likely cause a small, localized resuspension of sand and sand/silt when the pile is first set in place; as driving continues, little sediment would be expected to be released. Further from shore, the marine clays in the area near the end of the pier and at the mooring dolphins are more cohesive and would not be expected to be displaced. Therefore, although some low-level sediment contamination was identified in the general area of the proposed pier, it is not expected that pile driving with a vibrohammer would result in the resuspension of these sediments. Construction vessels may create minor amounts of sediment suspension due to propeller wash, but given the tidal fluctuations and the deep water in this area, this disturbance would be minor and temporary. In addition, the use of over-top construction methods in shallow waters and jack-up barges in deeper waters would minimize construction vessel activity that could result in the resuspension of sediments. Therefore, because of the use of these construction methods, including pile installation by vibrohammer, we have determined that construction and operation of the proposed project would not result in any significant impacts on water quality within Mill Cove, the St. Croix River, or Passamaquoddy Bay.

**Conclusions**

With the implementation of the BMPs associated with Downeast's Plan, Procedures, *Soil Erosion and Sediment Control Guidelines,* as discussed in more detail above, we believe that impact on soils or sediments from construction and operation of the proposed project would be minimal.

## 4.3 WATER RESOURCES

### 4.3.1 Groundwater

#### 4.3.1.1 Regional Groundwater Quality and Quantity

Aquifers in the area of the proposed LNG terminal site and pipeline route in Washington County, Maine consist of a surficial aquifer system and a consolidated bedrock system. The surficial aquifer system consists of glacial deposits of sand, gravel, and glacial till that were laid down during several advances and retreats of continental glaciers that encroached from the north or northwest. The glacial stage between the most recent advance, which took place about 21,000 years ago, and final retreat, which occurred about 12,000 years ago, is termed Wisconsinan. During this stage, ice covered all of the project area. The glacial ice and meltwater derived from the ice laid down several characteristic deposits. Till, which consists of unsorted and unstratified material ranging in size from clay to boulders, was deposited directly from the ice and is present under much of the proposed pipeline route. Meltwater laid down outwash, which consists mostly of stratified deposits of sand and gravel; ice-contact deposits, which consist primarily of poorly stratified sand and gravel; and near the coast, glacial-marine deposits, which consist of mostly clay, silt, and fine sand.

The bedrock aquifers are typically crystalline-rock aquifers that consist of almost insoluble igneous and metamorphic rock. These aquifers are characterized by shallow fracture systems that store and transmit water. The quantity of water yielded is dependent on the size and quantity of fractures; yields can vary from several to hundreds of gpm. Median total dissolved solids concentrations in water from these aquifers is low and typically ranges from 110 to 150 milligrams per liter. Water in crystalline-rock aquifers is similar in quality to water in aquifers of the surficial aquifer system. Locally, excessive concentrations of iron, manganese, and sulfate are present. Large concentrations of radon, a radioactive gas that is a decay product of the uranium minerals present in granite and some metamorphic rocks, have been reported in water from the crystalline-rock aquifers in all of the New England states except Vermont. The susceptibility of the crystalline-rock aquifers to contamination from the land surface is greatest where they are exposed at the land surface.

The crystalline bedrock aquifer is a confined aquifer composed of a variable complex of igneous and metamorphic rock. Well depths typically range between 20 and 800 feet and well yields are typically between 2 and 10 gpm in Maine. Elevated levels of iron, manganese, and radon gas are present in some areas in Maine.

EPA-designated sole source aquifers are those that contribute more than 50 percent of the drinking water to a specific area and for which there are no reasonably available alternative sources of water should the aquifer become contaminated. There are no sole source aquifers in the project vicinity (EPA 2008).

#### 4.3.1.2 LNG Terminal

**Groundwater Quality**

Downeast assessed the groundwater resources at the proposed LNG terminal site. Several test borings were completed, monitoring wells installed, and a deep bedrock well installed as a potential drinking water source. Surficial deposits ranged from 5 to 30 feet thick, depth to groundwater ranged from 3 to 15.5 feet below the ground surface, and the bedrock at the site is reported to be a coarse grained conglomerate. Groundwater samples were collected from two monitoring wells and the deep bedrock well. Samples were analyzed using accepted EPA methods for volatile organic compounds (VOCs), SVOCs, RCRA 8 metals, herbicides, pesticides, PCBs, and the drinking water quality-specific parameters nitrates/nitrites, total Kjeldahl nitrogen (TKN), ammonia, sodium, chloride, pH, and conductivity. The chemical testing results were compared to Maine Maximum Exposure Guidelines (MEGs) and EPA Maximum Contaminant Levels (MCLs), which are used as drinking water standards by the Maine Department of Health and Human Services, Division of Environmental Health, Drinking Water Program (DWP). Detected concentrations in samples from the two monitoring wells were below all MEGs and MCLs. The sample from the deep bedrock well contained sodium and antimony at concentrations above the MEG. Future sampling will determine if treatment would be required by the Maine DWP as part of their regulating this well as a public drinking water supply.

Based on a review of public water supply well information obtained from the Maine Office of Geographic Information Services (Maine GIS), Downeast identified no public water supply wells or related wellhead protection areas within 150 feet of the proposed construction area of the LNG terminal facility (Maine Office of GIS 2006a). Downeast completed searches of federal and state databases to identify sites that potentially have groundwater contamination within 0.5 mile of the proposed LNG terminal facility. No potentially contaminated groundwater sites were identified for the LNG terminal facility in any database searched.

### Impacts and Mitigation

Minor amounts of groundwater would be used during construction of the LNG terminal for miscellaneous construction purposes (e.g., dust suppression). In addition, some dewatering may be necessary during construction at the proposed LNG terminal site, since groundwater was found as shallow as 3 feet below the ground surface. However, relatively small volumes would be expected and effects to the overall groundwater system would be small and temporary. Bedrock was also encountered at depths as shallow as 5 feet in borings conducted at the terminal site, and therefore, blasting may be required in some areas. See section 4.1 of this EIS for more detailed discussion on blasting at the LNG terminal location. Blasting could cause areas of increased turbidity in groundwater near the blast area. These impacts would be expected to be short-term and localized in both lateral and vertical extent. No long-term impacts on groundwater quality would be expected. In addition, there are no wells in this area that could potentially be affected.

During operations, the LNG terminal would require a potable water source with a continuous freshwater flow rate of approximately 0.6 to 1.2 gpm, with a maximum daily usage of 990 gallons. Based upon sampling and analysis of monitoring wells, it appears that an adequate and acceptable water supply exists in the bedrock beneath the LNG terminal. A potential water supply well that Downeast has installed at the terminal could be an adequate potable water source, if permitted by the state, with a stable yield of 7.5 gpm. Groundwater would also be used to initially fill the vaporizers prior to SCV system startup. Approximately 20,200 gallons of water would be required. Downeast has stated that water from the on-site wells, commercial distributors, or a combination of both would provide the initial water volume for startup of the

SCV units. For major maintenance work requiring the water from an SCV unit to be drained, water from the in-service vaporizers would be used to fill empty vaporizer water baths. The Downeast LNG terminal would utilize an on-site wastewater disposal system for wastewater generated by the employee sanitary facilities. Because there is no public sewer system in the proposed terminal area, two subsurface wastewater disposal systems would be required (one each for the Administration and Operations buildings). Downeast would construct and operate these systems in accordance with the state regulations specific to subsurface wastewater disposal. Bathroom facilities associated with the pier control building would be discharged into an approved wastewater disposal holding tank whose contents would be disposed of at a state-approved septic disposal facility.

The greatest potential for impacts on groundwater would be an accidental release of a hazardous substance, such as fuels, lubricants, and coolants, during construction or operation. Spills or leaks of hazardous liquids could contaminate groundwater and affect users of the aquifer. This type of impact could be avoided or minimized by restricting the location of refueling or storage facilities and by requiring immediate cleanup of spills. Downeast's Plan, Procedures, and Soil Erosion and Sediment Control Guidelines include the preparation and implementation of Spill Prevention and Response Procedures that meet state and federal requirements. Downeast has developed a SPCC Plan template, which it would provide to all construction subcontractors who would be required to develop project-specific SPCC Plans that would be implemented during construction of the facilities. These SPCC Plans would address potential spills of fuel, lubricants, and other hazardous materials and describe spill prevention practices, spill handling and emergency notification procedures, and training requirements. They would also describe mitigation measures, including containment and cleanup, to minimize potential impacts should a spill occur. We have reviewed Downeast's SPCC Plan template and find it adequate. Implementation of Downeast's proposed measures would minimize the potential for impact on groundwater.

#### 4.3.1.3 Sendout Pipeline

**Public Water Supply and Wells**

The sendout pipeline route crosses designated significant sand and gravel aquifers from MP 13.8 to MP 14.1, MP 25.4 to MP 25.5, and MP 28.4 to MP 29.0 (see figure 4.3-1). Significant sand and gravel aquifers are areas designated and mapped by the MGS as consisting of significant sand and gravel deposits that have the potential to supply a properly constructed well with a yield of at least 10 gpm.

Maine GIS data show that one WPA, the Baileyville WPA, would be traversed by the proposed sendout pipeline route between approximately MP 25.4 and MP 25.6, and between approximately MP 28.6 and MP 28.7 (see figure 4.3-2). The Baileyville WPA is a wellhead protection zone associated with two public water supply wells utilized by a community public water system in Baileyville (Maine GIS 2006a). The Maine DWP establishes WPAs around designated public water supply wells to protect groundwater quality in the vicinity of the well from adverse environmental impacts through restrictions of various operations and land uses within the designated area. The Maine DWP WPAs range from 300 to 2,500 feet in radius depending on the classification of the system and the number of people served.

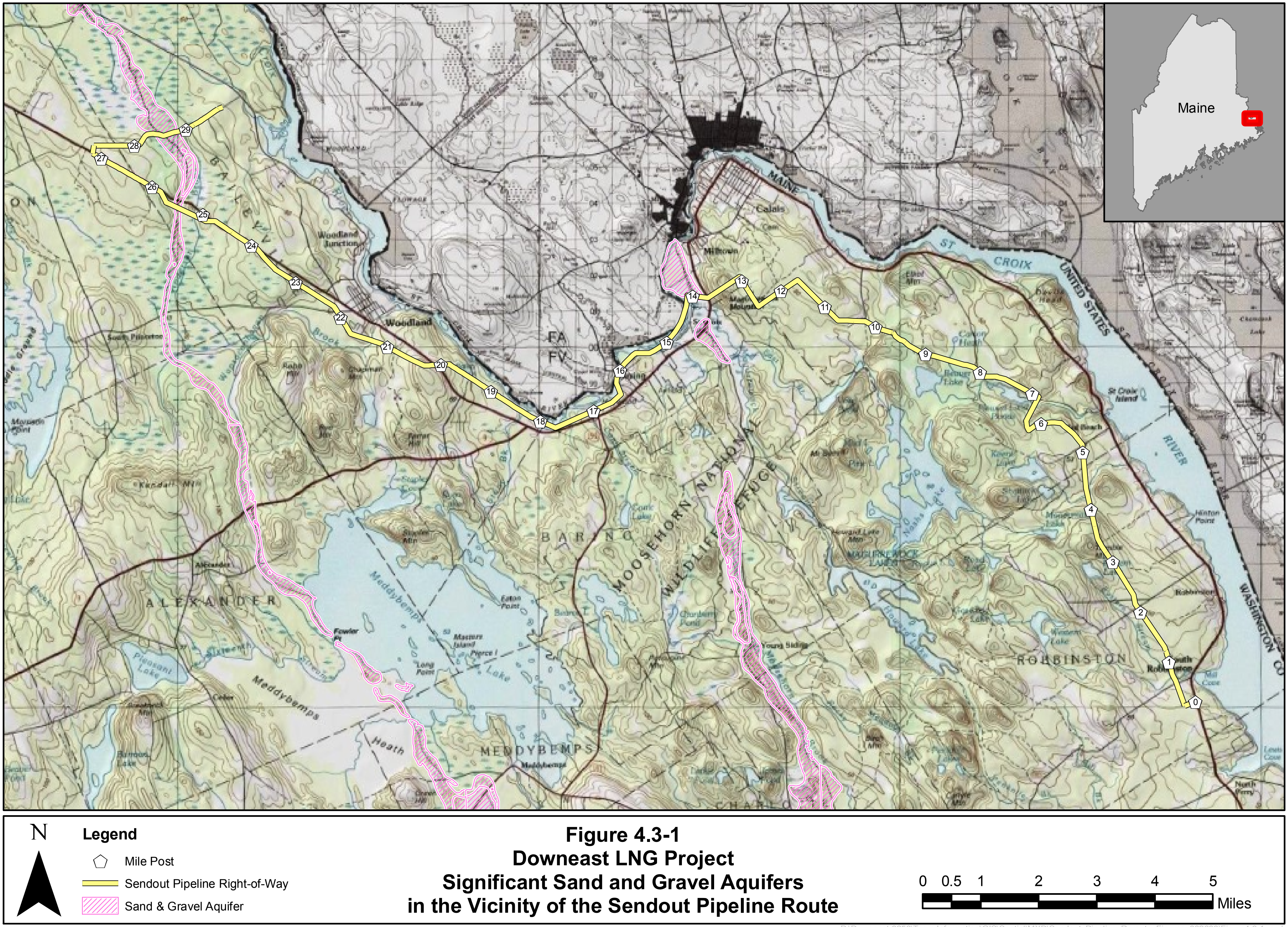


**Figure 4.3-1**
**Downeast LNG Project**
**Significant Sand and Gravel Aquifers**
**in the Vicinity of the Sendout Pipeline Route**

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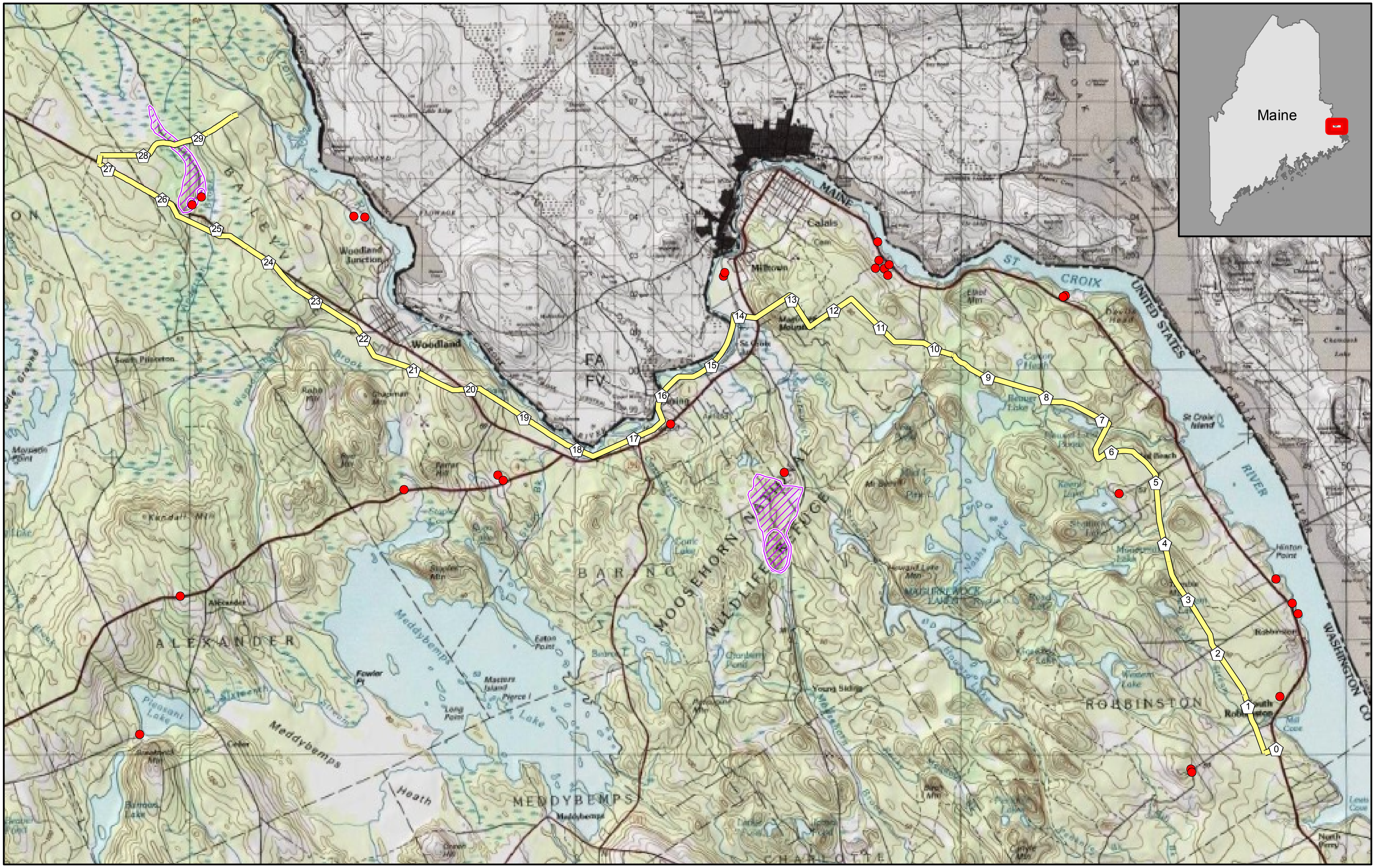


**Figure 4.3-2**
**Downeast LNG Project**
**Public Water Supply Wells and Wellhead Protection Areas**

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The two wells operated by the BUD are designated Well #1 (Maine Well ID 90100201), the southern-most well located closer to the sendout pipeline route, and Well #2 (Maine Well ID 90100202) located to the northeast of Well #1; however, neither of these wells are within 150 feet of the proposed sendout pipeline route (see figure 4.3-2). Both Well #1 and Well #2 are shallow gravel packed wells installed in sand and gravel deposits that do not extend into the underlying bedrock. Well #1 was drilled in 1963 to a depth of 72 feet below ground surface and has a yield that varies from 5 to 50 gpm. Well #2 was drilled in 1995 to a depth of 63 feet below ground surface and has a yield of 750 gpm (BUD 2006). BUD indicated that Well #1 has been used only on occasion as a backup water source since the installation of Well #2.

As shown on figure 4.3-2, the Baileyville WPA also includes a "finger" trending north-northwest of the well's radial protection zone that encompasses an important part of the aquifer. This area is hydrologically connected to the radial protection zone and is the area that supplies much of the water to the Baileyville wells.

Downeast has identified 18 private homes within 50 feet of the proposed sendout pipeline permanent right-of-way in areas where public water supplies are not available. Downeast states that it is coordinating with landowners to collect and record the locations of private water supply wells within 150 feet of the limits of construction. With authorization from the well owner, Downeast would evaluate individual private wells within 150 feet of the pipeline route and test the well's water quality before and after construction.

**Groundwater Quality**

Downeast completed searches of federal and state databases to identify sites that potentially have groundwater contamination within 0.5 mile of the proposed sendout pipeline route. Lists of the identified sites, locations, and approximate milepost along the proposed pipeline route for each database search are shown on tables 4.2.7.2-1 and 4.2.7.2-2. Sources of potential groundwater impacts associated with the listed sites include leaking petroleum storage tanks, auto body facilities, injection sites, surface spills, a landfill, and salt storage facilities.

Downeast performed a field survey of the proposed pipeline route to observe the identified sites and assess the potential of encountering contaminated conditions during construction of the proposed pipeline. With the exception of the Irving Big Stop at MP 18.1, the Baileyville Town Site at MP 20.4, and the Secondary Lagoons Site at MP 20.5, the identified potential contaminated areas appear to be at locations that would be considered hydraulically downgradient from the pipeline route and/or at distances that would not likely impact subsurface conditions beneath the pipeline alignment. Although the Irving Big Stop appears upgradient of the pipeline route, no evidence of potential impacts, including stressed vegetation, were observed in an adjacent wetland area between the pipeline route and the Irving facility and no groundwater remediation systems were observed in the vicinity of the Irving Big Stop.

The Baileyville Town Site includes the Baileyville landfill facility and related secondary leachate lagoons that are upgradient of the pipeline route. Based on topographic and geologic conditions in this area, pipeline construction activities may not encounter groundwater and potential remedial actions associated with impacted groundwater and sediments would not be required. Downeast would perform subsurface explorations within the pipeline right-of-way in the vicinity of both the Irving Big Stop and the Baileyville Town Site to assess potential contamination that may be encountered during pipeline construction activities in these areas. Downeast would contact Maine DEP and landowners to determine whether impacted soils or groundwater may be present in the area of construction since it is possible that contaminated soils or groundwater could be encountered. In the event that unanticipated areas of contamination are encountered, Downeast would, in consultation with Maine DEP, implement the appropriate remedial actions.

State and local officials have expressed concern about a contaminated site that was not identified by Downeast because of its location outside the 0.5 mile zone. The BUD and the Maine Center for Disease Control and Prevention have expressed concern over the potential relationship of the proposed pipeline between MP 25.4 and MP 25.5 and an abandoned special waste landfill located approximately 0.75 mile south of the proposed alignment. A significant sand and gravel aquifer is present in this area. This landfill is hydraulically downgradient of the proposed alignment. The specific concern expressed is that the proposed HDD here could alter groundwater flow patterns and potentially cause contaminated groundwater associated with the landfill to migrate north towards the Baileyville WPA. Although the installation of the pipeline would affect groundwater flow in the immediate area around the pipeline (in areas beneath the water table, the flow would be diverted around the pipeline), the overall groundwater flow direction in the area would not be affected. Thus, because of the groundwater flow direction in this area, and the distance between the abandoned landfill and the proposed pipeline, we believe that the installation and presence of the pipeline in this area would not cause a threat to the WPA.

**Impacts and Mitigation**

In general, construction and operation of the proposed pipeline would have little or no adverse effects to groundwater resources. Blasting could potentially occur in areas of shallow bedrock along the proposed sendout pipeline route (see section 4.1 for details regarding blasting). Prior to the start of blasting work, Downeast would perform a pre-blast conditions survey of all existing structures and conditions in the vicinity, including all water supply wells within 150 feet of a blasting area. The pre-blast surveys would include locating the well, documenting the current condition of the well, determining the well yield, and performing analytical testing of the drinking water. Downeast states that before completion of the pre-blast surveys, it would develop a specific procedure for recording, processing, and responding to well damage claims that arise during construction. Downeast would conduct a follow-up round of testing, including well yield and analytical testing, for wells for which claims are filed. The results of the follow-up tests would be compared with the pre-blast test results to help assess potential damage to the well. We agree with this general approach, but would require follow-up testing regardless of whether a claim were filed, because impacts on yield and water quality may not be immediately discernible to the well owner. Because Downeast has not completed surveying the entire pipeline route for private wells, **we recommend that:**

- **<u>Prior to construction of the pipeline facilities</u>, Downeast should file with the Secretary the location by milepost of all private wells and springs within 150 feet of construction activities. Downeast should conduct, with the well owner's permission, pre- and post-construction monitoring of well yield and water quality for these wells. In the event a water well or system is damaged as a result of construction, Downeast should arrange for a temporary source of potable water, if required, and provide for the repair of the well or replacement of the water supply.**

In addition, we believe that Downeast should be responsible for any water system that it damages and cannot repair to pre-construction yield or quality. Therefore, **we recommend that:**

- **<u>Within 30 days of placing the pipeline facilities in service</u>, Downeast should file a report with the Secretary discussing whether any complaints were received concerning well yield or water quality of the private wells and springs within 150 feet of construction activities and how each complaint was resolved.**

If shallow groundwater is encountered during excavations along the pipeline route, it may be necessary to dewater during construction. Trench dewatering operations would be brief, typically lasting several days or less. Potential impacts on the groundwater would include minor fluctuations in groundwater levels and/or increased turbidity within the aquifer adjacent to the activity. Because of the relatively small amount of water removed, the short duration of the activity, and the local discharge of the water, groundwater levels would quickly recover after pumping stops. Downeast would follow its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* that provide guidance on the location of dewatering structures so that there would be no deposition of sediments into wetlands and waterbodies, and no impacts on cultural resources or habitat for sensitive species. We believe that effects of dewatering on groundwater would be localized, temporary, and insignificant.

During pipeline construction activities, it is possible that HDD boreholes could penetrate local shallow aquifers. However, these activities are not expected to impact groundwater conditions other than in the immediate vicinity of the borehole, where bentonite drilling mud could result in localized alteration of aquifer hydraulic properties. Temporary dewatering activities that may occur on the St. Croix River HDD would be localized, passive dewatering to keep any entry/exit HDD trench and work area dry for worker safety during construction, should it be necessary. Where the pipeline would be installed below the groundwater table, the groundwater levels would stabilize back to equilibrium conditions around the pipeline immediately upon completion of construction activities. The construction and operation of the pipeline is not expected to have permanent effects to groundwater flow patterns or aquifers. Additionally, we have recommended that wells within 150 feet of construction areas be monitored to evaluate water quality, which would detect any localized changes that might occur in response to the HDD activities.

The greatest potential for impacts on groundwater would be an accidental release of a hazardous substance, such as fuels, lubricants, and coolants, during construction or operation. Spills or leaks of hazardous liquids could contaminate groundwater and affect users of the aquifer. This type of impact could be avoided or minimized by restricting the location of refueling or storage facilities and by requiring immediate cleanup of spills. Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* include the preparation and implementation of Spill Prevention and Response Procedures that meet state and federal requirements. Downeast has developed a SPCC Plan template, which it would provide to all construction subcontractors who would be required to develop project-specific SPCC Plans that would be implemented during construction of the facilities. These SPCC Plans would address potential spills of fuel, lubricants, and other hazardous materials and describe spill prevention practices, spill handling and emergency notification procedures, and training requirements. They would also describe mitigation measures, including containment and cleanup, to minimize potential impacts should a spill occur. We have reviewed Downeast's SPCC Plan template and find it adequate.

Downeast has made a commitment to take special care in maintaining good housekeeping and spill prevention and control practices during pipeline installation and maintenance in areas overlying the significant sand and gravel aquifers from MP 13.8 to MP 14.0, MP 25.4 to MP 25.5, and MP 28.4 to MP 29.0, and particularly for the proposed crossing of the Baileyville WPA between MP 25.4 and 25.6, and between MP 28.6 and MP 28.7. Based on these assurances, in a letter dated August 8, 2008 to Gardner Rolfe of the BUD, Andrew L. Tolman, Assistant Director of the Maine CDC Drinking Water Program, indicated that the "current pipeline alignment does not appear to pose a significant threat to the public water supply."

### 4.3.2 Surface Water

#### 4.3.2.1 LNG Terminal

**Offshore Construction**

The proposed LNG terminal pier would be located in Mill Cove slightly south of the confluence of Passamaquoddy Bay and St. Croix River. The outlet of Passamaquoddy Bay exchanges water with the Bay of Fundy (see figure 4.3-3). This general area is known for its extreme tidal range and swift currents. These conditions cause the coastal waters of the area to be very well mixed, thereby allowing any minor changes in water temperature or sediment load to be quickly dispersed.

The waters of Passamaquoddy Bay and the St. Croix River/Mill Cove are classified by the state of Maine as SB. A Class SB designation in the state of Maine is the second highest water classification in terms of overall water quality. Class SB waters must be of such quality that they are suitable for the designated uses of recreation in and on the water, fishing, aquaculture, propagation and harvesting of shellfish, industrial process and cooling water supply, hydroelectric power generation, navigation, and as habitat for fish and other estuarine and marine life. The habitat under this classification is characterized as unimpaired.

Construction of the Downeast LNG terminal pier could adversely affect surface water quality in Mill Cove, the St. Croix River, and Passamaquoddy Bay during the construction period. The primary impacts on these surface waters from construction of the project would be from turbidity increases around pier support pilings during pier construction, stormwater runoff, and accidental spills or leaks of hazardous materials. No in-water dredging is proposed.

Construction of the pier would likely result in minor increases in suspended solids in the water column in the vicinity of pile-driving activities. However, based on our previous consultations with resource agencies and information obtained from other pile-driving projects (Balloch 2007), we believe that pile driving does not typically result in the release of a substantial amount of sediment into the water column. In addition, for the types of sediments found in the area of the proposed pier near the shore (sand and sand/silt), a small, localized release would occur when the pile is first set in place, but as driving continues, little sediment would be expected to be released. The marine clays found farther offshore in the area near the end of the pier and at the mooring dolphins would also not be expected to be displaced as they are cohesive.

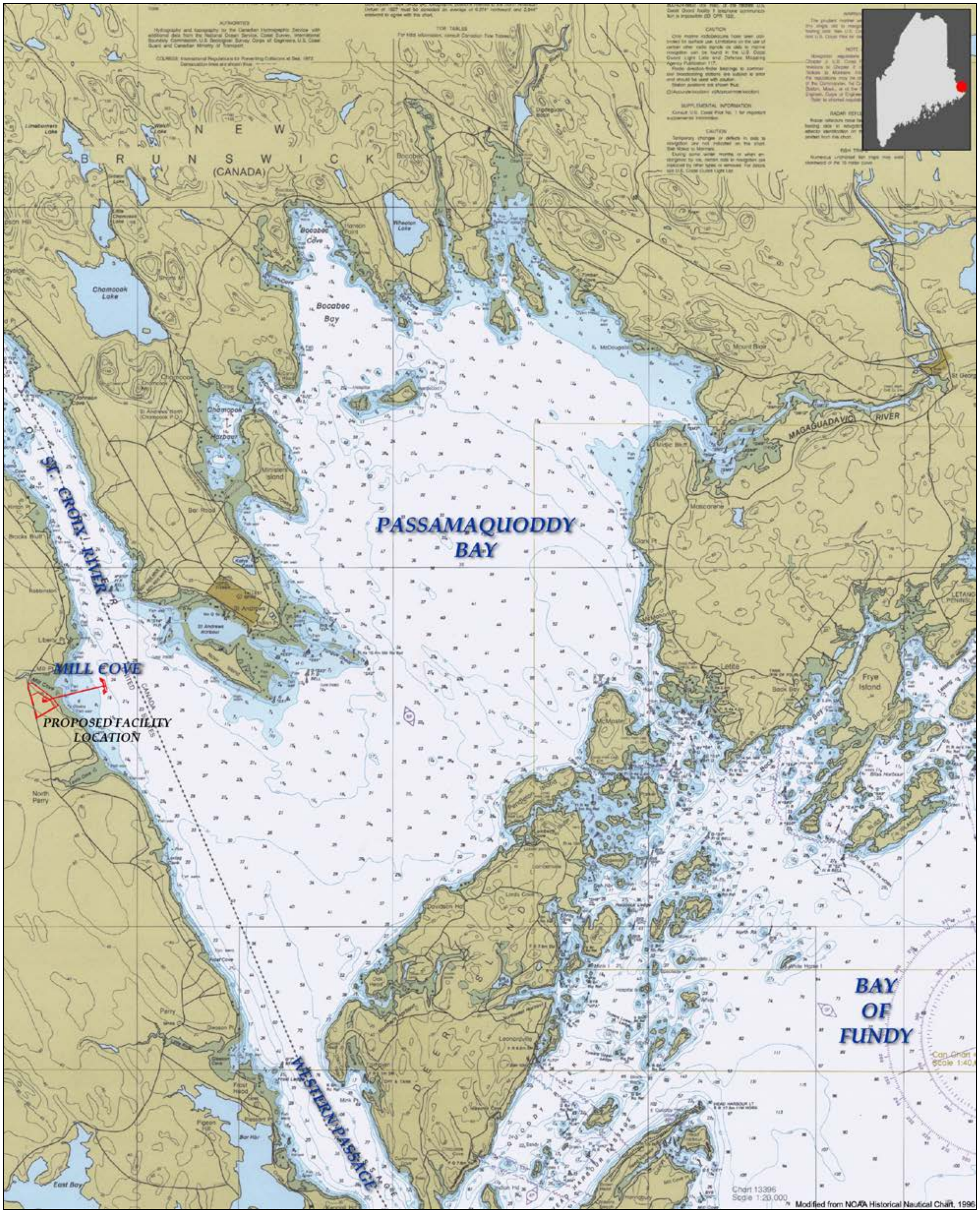


**Figure 4.3-3**
**Downeast LNG Project**
**Passamaquoddy Bay and Fundy Isles**

Although some low-level sediment contamination was identified in the general area of the proposed pier, it is not expected that pile driving would result in the resuspension of these sediments, and therefore, would not result in any significant impacts on water quality within Mill Cove, the St. Croix River, or Passamaquoddy Bay. Section 4.2.8 of this EIS discusses the results of sediment sampling and geotechnical investigation in the area of the proposed pier.

During rock socket drilling activities, drill cuttings would also be produced and released into the water column; however, it is unlikely that these heavy coarse drill cuttings would become suspended and contribute measurably to the levels of total suspended solids. Additionally, the currents and substantial water turnover near the project area from the extreme tides would aid in dispersing any suspended materials.

Marine construction vessels operating near the shoreline could also result in the suspension of some sediments via propeller wash. However, these impacts would be limited to the construction time frame and therefore would be temporary. In addition, the use of over-top construction methods in shallow waters and jack-up barges in deeper waters would minimize construction vessel activity that could result in the resuspension of sediments. In deeper waters where support vessels would be required for construction, the under keel depth would average 25 feet.

Vessels working to construct the offshore portions of the LNG terminal require the use of fuel and other lubricants to support vessel and equipment operation; as a result, there is potential for the inadvertent release of fuel to the waters of Mill Cove and Passamaquoddy Bay. To prevent and/or minimize impacts associated with accidental spills or releases during construction, all contractors are required to comply with state and federal (Coast Guard) regulations related to fuel handling and spills in offshore areas. In accordance with 33 CFR Part 151.29, each oil tanker of 150 gross tons and above and each other ship of 400 gross tons and above, operated under the authority of a country other than the U.S. that is party to MARPOL 73/78, shall, while in navigable waters of the U.S. or while at a port or other terminal under the jurisdiction of the U.S., carry on board a shipboard oil pollution emergency plan (SOPEP) approved by its flag state. This plan shall meet the requirements set forth in 33 CFR Part 151.26 and 33 CFR Part 156.20. Additionally, the Maine DEP requires that it be notified in the event of any discharge of oil in or next to waters of the state.

For smaller vessels that are not required to have an SOPEP, the volumes of fuel potentially involved are expected to be on the order of tens of gallons. Implementation of standard spill response techniques for spills of this size should minimize adverse impacts on the water quality of Mill Cove and Passamaquoddy Bay. Such impacts would be expected to be short-term in nature, as quantities of spilled fuel not able to be collected would likely be minor and would be dispersed and diluted by wind and wave action. However, because there are no procedures specified for spills from smaller vessels that could occur in the waters of Mill Cove and Passamaquoddy Bay during construction of the marine terminal, **we recommend that:**

- **<u>Prior to construction of the LNG terminal facilities,</u> Downeast develop a Marine SPCC Plan to include procedures that would be implemented should spills of oil, gas, lubricants, or other hazardous materials occur during construction and operation of the marine terminal. In addition to addressing emergency spill response and cleanup procedures, this plan should include a description of general**

**spill prevention measures such as material handling practices, personnel training, and inspection. Downeast shall file the Marine SPCC Plan with the Secretary for review and written approval by the Director of OEP.**

**Onshore Construction**

The proposed onshore portion of the Downeast LNG terminal is located along the southern shores of Mill Cove within the Robbinston watershed. The only mapped surface waterbody at the proposed Downeast LNG terminal site is a small Maine DEP jurisdictional stream that flows from a culvert under U.S. Route 1 to the northeast, where it discharges into Mill Cove. Downeast states that the stream is approximately 5 to 7 feet wide with well-defined banks. Also present near the southeastern boundary of the proposed terminal site is a swale draining a wetland that discharges to Passamaquoddy Bay.

During site preparation and construction at the LNG terminal site, disturbed soils would be exposed to erosion. To minimize erosion impacts on surface waters, Downeast would comply with the Maine Stormwater Management Law's requirement for preparing a Construction General Permit for stormwater discharges during construction. In addition, the Maine Erosion and Sedimentation Control Law requires preparation and implementation of an Erosion and Sedimentation Control Plan. We believe that Downeast's use of its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* during onshore construction would meet the intent of the Maine Erosion and Sedimentation Control Law and would minimize impacts from erosion on surface waters during construction.

In the event of an accidental spill of oil, gas, lubricants, or other hazardous materials during construction or operation, Downeast would follow the measures outlined in the project-specific SPCC Plans to be prepared by each subcontractor.

Prior to being placed into service, the proposed LNG storage tanks and sendout pipeline would be hydrostatically tested to ensure structural integrity. However, because of the length of time required to construct the LNG storage tank, Downeast anticipates that its hydrostatic testing would not occur until over three years after this EIS is published. Hydrostatic testing procedures for the LNG storage tanks are discussed below; procedures for testing the pipeline are discussed in section 4.3.2.2.

Once construction is completed, the LNG storage tanks would be hydrostatically tested, in accordance with API Standard 620, Appendix Q.8 (see section 2.3.1.3). Hydrostatic testing of each tank would involve filling the inner tank with approximately 28 million gallons of water. Water used for the hydrostatic testing of the first tank would also be used to test the second tank. Downeast states that although a combination of sources may be used (water from the on-site deep well, water trucked in from a municipal or industrial supply, or Passamaquoddy Bay water), the principle source of test water would likely be from Passamaquoddy Bay. The use of saltwater would have no effect to the tank or tank components that would come into contact with the saltwater. However, because the same water would be used to test both tanks, water may need to be retained in the first tank for approximately one month, although the duration will be kept to a minimum. As a result, chemicals and/or biocides may need to be added to the water in the storage tank for corrosion control and to inhibit biological growth. The contents of the tank would be tested to determine whether or not treatment would be required and to determine the amount and type of chemical and/or biocide that would need to be added. Once transferred to the second tank, the water would be held for at least 48 hours for inspection.

After testing, the tanks would be cleaned with fresh water and dried. Pumps in the tank would control the discharge rate of the test water. Test water would be discharged into Passamaquoddy Bay using a pipeline fitted with an aeration type energy dissipater to allow the test water to be sprayed into Passamaquoddy Bay to prevent potential erosion and scouring of the bottom sediments. The state of Maine has assumed the NPDES program from the federal government, and issues its permits through the Maine DEP. Hydrostatic test waters that would be discharged into waters of the state would require a permit under the Maine PDES, as regulated by the CWA. The discharge rate would be in compliance with that established in the hydrostatic test water Maine PDES permit. Prior to discharge, all test water would be analyzed for chemical composition as determined in the Maine PDES permit. If no chemicals or biocides are used in the hydrostatic test water, Maine DEP has indicated that a total suspended solids analysis would be the only analysis required.

**Operation**

As proposed, the pier would have more than adequate water depth for the LNG vessels and as this is currently not a depositional area, it appears that maintenance dredging would not be necessary. Thus no impacts from dredging would be expected. Propeller wash from tugs and/or LNG vessels equipped with thrusters would not be expected to increase turbidity in Passamaquoddy Bay because the sediments in this area appear to be cohesive, soft marine clays (see section 4.5.2.2). In addition, the shoreline adjacent to the pier would include erosion protection (e.g., articulated concrete blocks) placed on slopes to stabilize the shoreline and prevent erosion from wave action and propeller wash from the LNG vessels.

Prior to operating the LNG terminal, Downeast would need to apply for a Multisector General Permit concerning management of stormwater from the LNG terminal facilities. As part of this requirement, a SWPPP would also be prepared to comply with Maine DEP and EPA requirements concerning stormwater runoff due to the impervious surfaces at the LNG facility. The state of Maine has assumed the NPDES program from the federal government, therefore stormwater discharges would be regulated by the Maine DEP PDES program. Stormwater discharges would be directed to the Maine PDES permitted discharge points. This plan would also list prevention and response procedures in the event of an accidental spill of oil, gas, lubricants, or other hazardous materials.

Downeast would design its LNG terminal to account for an accidental spill of LNG during operation of the facility, and prevent the LNG from entering Passamaquoddy Bay. The LNG facilities would include safety and hazard detection systems, LNG containment and process sumps, and associated LNG spill collection system.

The SCV technology that would be used to process the LNG produces excess water at a rate of 85 gpm when the LNG terminal is operating at normal sendout capacity, and up to 109 gpm during peak capacity. This equates to a 24-hour discharge of between 122,400 and 156,960 gallons. During the vaporization process, this excess water would be acidic, but would not be contaminated with any foreign substances. Downeast would be required to neutralize the excess water by adding sodium hydroxide to the SCV water bath prior to its final discharge.

Downeast proposes to use recovered SCV water to supply its firewater system and sell surplus SCV water (not used on-site) to an independent party yet to be identified for off-site use. Downeast states that it is in discussions with several such parties and is confident that a buyer for this water would be contracted. Therefore, **we recommend that:**

- **<u>Prior to construction of the LNG terminal facilities</u>, Downeast should file with the Secretary a final plan for the discharge of the excess SCV water, for the review and written approval of the Director of OEP. The discharge plan should include discharge location, rate and frequency of discharge, copies of applicable permit applications, and all measures to be used to mitigate environmental impacts at the discharge location.**

As with other large tank ships, LNG vessels would take on some ballast water to maintain vessel trim and stability, and keep the vessel's hull within acceptable stress levels as they offload their cargo and depart the LNG terminal. The amount of ballast water required by each LNG vessel would vary according to its size and the weather conditions. Downeast states that, although the LNG terminal berth and offloading facility would have the potential to handle future vessels of 220,000 $m^3$, the largest vessel that would be accommodated at the import facility would be a 165,000 $m^3$ LNG vessel. Such a vessel would require about 17.11 million gallons of water, which would be obtained in Passamaquoddy Bay and transported out of the waterway. This quantity is estimated to be about 0.0003 percent of the quantity of water that flows in and out of Passamaquoddy Bay during one tidal cycle. This would constitute a minor impact on water resources of Passamaquoddy Bay. Impacts on ichthyoplankton and zooplankton species from LNG vessel water withdrawals are discussed in detail in section 4.5.2.2 of this EIS.

Although ballast water intake by the LNG vessel would occur during offloading of the LNG, no release of ballast water would occur within the navigable waters of the United States. Any limited discharge of ballast water that should occur would be conducted in accordance with the Coast Guard's mandatory ballast water management program (33 CFR 151).

The presence of the pier support structures underwater would alter the local hydrodynamic regime of Passamaquoddy Bay to a minor degree. In the areas immediately surrounding the support structures, current patterns would be affected, an increase in localized turbulence in the water column would occur, and bottom sediment scouring or deposition patterns immediately adjacent to the structures could change. We do not believe that these changes would cause any noticeable negative impact on the water resources of Passamaquoddy Bay.

Other potential impacts on water resources involve the uptake of water from Passamaquoddy Bay for emergency firewater pumps. The primary source of water for the firewater system would be water recovered from SCVs. However, backup firewater would be provided from emergency firewater pumps that would be installed on the pier and would use water from Passamaquoddy Bay. The backup firewater system would also be used at any time that an LNG storage tank deluge system is in operation. These pumps would draw water from Passamaquoddy Bay and would be capable of supplying water directly to the pier, to the LNG storage tank deluge, and to the firewater storage tank to provide emergency makeup for the firewater system. One of each of the seven emergency firewater pumps would be tested for one hour once a week at a rate of 3,000 gpm for a total of 180,000 gallons/week. This water would be sprayed back into Passamaquoddy Bay; this activity would constitute a negligible impact on water resources of Passamaquoddy Bay. Impacts on ichthyoplankton and zooplankton species from LNG vessel water withdrawals are discussed in detail in section 4.5.2.2.

LNG vessels would also require water withdrawals and discharges while at the port for vessel operations. The majority of this water would consist of engine cooling water that is recirculated or cycled through a heat exchanger before being discharged back to Passamaquoddy Bay. Downeast has provided information indicating that a 165,000 $m^3$ LNG vessel would require a maximum of about 55.5 million gallons of water over a 21-hour period to support engine cooling while at the pier (a maximum average rate of 540 gallons per second). The temperature of this water at the point of discharge would be elevated by 5 to 10°F in comparison to the receiving waters of Passamaquoddy Bay. However, Cornell Mixing Zone Expert System (CORMIX) modeling conducted by Downeast indicates that the discharge plume associated with engine cooling would be relatively minor, with the change in temperature reduced to approximately 1°C, or less, warmer than ambient conditions within 15 to 30 meters of the point of discharge, at ambient current speeds of 0.5 m/s and 0.05 m/s, respectively (see Appendix O). Due to the comparatively small volume of this water in relation to the flow of Passamaquoddy Bay (estimated to be about 0.001 percent of the quantity of water that flows in and out of Passamaquoddy Bay during one tidal cycle), and the swift currents that would cause rapid mixing, we believe that there would be no discernable impact on the water quality of Passamaquoddy Bay from cooling water discharge activities.

Another use of Passamaquoddy Bay water could be reverse osmosis (RO) desalination that would produce fresh water for hoteling. The RO process waste product is concentrated brine that would be discharged to Passamaquoddy Bay. Given the results of the CORMIX modeling and the flow rate of Passamaquoddy Bay, we expect that the brine would mix rapidly with Passamaquoddy Bay waters with no discernible impact on the water quality of Passamaquoddy Bay.

#### 4.3.2.2 Sendout Pipeline

The proposed sendout pipeline would cross 22 surface waterbodies. Of these, 14 would be minor crossings (less than 10 feet in width), 6 intermediate (between 10 and 100 feet wide), and 2 major (greater than 100 feet wide). The pipeline right-of-way occurs within the Coastal Washington and Hancock drainage area and the St. Croix River drainage area. Streams in these areas vary in substrate type, substrate particle size, channel width, flow regime, and depth. Depths are generally less than 10 feet and stream bottoms are a combination of woody debris and rocks generally no larger than 12 inches in diameter. Canopy closures over the streams ranged from zero to 100 percent, and Downeast states that the average canopy closure was 52 percent.

No waterbody segments that would be crossed by the pipeline are included on the list of impaired waterbodies under Section 303(d) of the CWA; however, Downeast states that all fresh waters in Maine are considered impaired by atmospheric deposition of mercury. There are no public surface water intakes for drinking water systems within 3 miles of the pipeline right-of-way.

Under Maine Statute Title 12, Chapter 200, Section 403, the Legislature granted special protection for *Outstanding River Segments* by declaring that "certain rivers, because of their unparalleled natural and recreational values, provide irreplaceable social and economic benefits to the people in their existing state." There are no *Outstanding River Segments* proposed to be crossed by the Downeast pipeline.

The National Rivers Inventory (NRI) is a list of rivers that contain values and resources that the National Wild and Scenic Rivers Act is designed to protect and enhance. The NRI lists "... river segments in the United States that are believed to possess one or more outstandingly remarkable values judged to be of more than local or regional significance" (NPS 2008). No NRI designated waterbodies would be crossed by the proposed pipeline.

None of the streams affected by the construction or operation of the Downeast pipeline are listed under the National Wild and Scenic Rivers Act (16 U.S.C. §1276) or are listed for potential designation by the National Park Service.

A list of the waterbodies crossed by the proposed sendout pipeline is included in table 4.3.2.2-1 and shows the location by milepost, waterbody name, state water quality classification, waterbody width/crossing length, crossing method, stream type, and fishery type.

Activities that could affect surface waters include clearing, grading, trenching, blasting, backfilling, and right-of-way maintenance. These activities could result in increased turbidity and sedimentation, decreased oxygen levels, increased stream temperatures, release of chemical and nutrient pollutants from sediments, and accidental release of chemical contaminants such as fuels and lubricants. Downeast states that because of their limited width and depth, most streams would likely be crossed using conventional backhoe-type equipment and dry open-trench techniques specified in Downeast's Plan, Procedures, and *Soil Erosion and Sediment Guidelines.* The dam and pump method is a dry-crossing technique that uses pumps to isolate water from the construction work area. This method is the preferred waterbody crossing technique to be employed by Downeast. Use of dam and pump crossing methods in flowing streams would reduce exposure of waterbodies to erosion and sedimentation, and thus reduce the overall impact on the waterbody. Downeast expects that most in-stream work within minor waterbodies would be completed within 24 to 48 hours. Trench spoils would be stored at least 10 feet from the water's edge and would have erosion and sedimentation controls installed. Stream banks would be stabilized and temporary sedimentation barriers installed across the right-of-way within 24 hours of completing in-stream construction. Therefore, most impacts would be temporary and suspended sediment concentrations and turbidity levels would be expected to return to preconstruction levels soon after construction in each stream was completed.

Because of the presence of known or suspected sites where soil and/or groundwater contamination may be present in the vicinity of the proposed pipeline route, it is possible that Downeast would encounter contaminated sediments in the waterbodies proposed to be crossed. Downeast has acknowledged this, and has stated that it would work with landowners to aid in identifying whether contaminated sediments may be present, develop construction procedures concerning contaminated sediments, and that it would notify Maine DEP if contaminated sediments were encountered.

As shown on table 4.3.2.2-1, Downeast proposes to cross 9 of the 22 waterbodies using the HDD crossing method. The HDD method involves boring a pilot hole beneath the waterbody to the opposite bank and then enlarging the hole with one or more passes of a reamer until the hole is the necessary diameter. A prefabricated pipe segment is then pulled through the hole to complete the crossing. A successful drill generally results in no impact on the waterbody being

TABLE 4.3.2.2-1

**Waterbodies Crossed by the Pipeline Route**

| Town | MP | Waterbody | Water Quality Classification a/ | Width/Crossing Length (linear ft) b/ | Crossing Method | Stream Type | Fishery Type c/ |
|---|---|---|---|---|---|---|---|
| Robbinston | 0.8 | Eastern Stream | B | 25 / 25 | Dam and Pump | Perennial | Cold-water |
| Robbinston | 2.0 | Unnamed stream | B | 4 / 4 | Dam and Pump | Intermittent | Warm-water |
| Robbinston | 4.3 | Unnamed stream (outlet of Keene Lake) | B | 9 /1,165 | HDD | Perennial | Cold-water |
| Calais | 6.7 | Flowed Land Ponds | B | 12 / 141 | HDD | Perennial | Cold-water |
| Calais | 7.7 | Unnamed stream (inlet to Flowed Land Ponds) | A | 7 / 7 | Dam and Pump | Perennial | Cold-water |
| Calais | 8.6 | Tributary of Beaver Brook (upstream of Flowed Land Ponds) | A | 10 / 2,629 | HDD | Perennial | Cold-water |
| Calais | 12.3 | Unnamed stream | A | 3 / 3 | Dam and Pump | Intermittent | Warm-water |
| Calais | 14.1-14.2 | Magurrewock Stream Outlet | A | 528 / 792 | HDD | Perennial | Cold-water |
| Calais/ Baring | 14.2-15.3 | St. Croix River | C | 3,000 / 5,829 | HDD | Major river | Cold-water |
| Baring | 15.6 | Unnamed stream | A | 3 / 3 | Dam and Pump | Intermittent | Warm-water |
| Baring | 15.6 | Unnamed stream | A | 3 / 3 | Dam and Pump | Intermittent | Warm-water |
| Baring | 16.9 | Conic Stream | A | 3 / 3 | Dam and Pump | Perennial | Warm-water |
| Baring | 17.2 | Unnamed stream | A | 3 / 3 | Dam and Pump | Intermittent | Warm-water |
| Baring | 17.6 | Unnamed stream, (tributary of St. Croix River) | A | 3 / 3 | Dam and Pump | Perennial | Warm-water |
| Baring | 17.8 | Unnamed stream, (tributary of St. Croix River) | A | 8 / 1,227 | HDD | Perennial | Warm-water |
| Baileyville | 18.1 | Unnamed stream, (tributary of St. Croix River) | A | 4 / 1,227 | HDD | Perennial | Cold-water |
| Baileyville | 18.4 | Stony Brook | A | 18 / 18 | Dam and Pump | Perennial | Cold-water |
| Baileyville | 21.3 | Wapsaconhagen Brook | A | 37 / 37 | Dam and Pump | Perennial | Cold-water |
| Baileyville | 22.5 | Unnamed stream (tributary of Wapsaconhagen Brook) | A | 4 / 4 | Dam and Pump | Perennial | Warm-water |
| Baileyville | 25.2 | Anderson Brook | A | 15 / 2,622 | HDD | Perennial | Cold-water |
| Baileyville | 25.8 (3 crossings) | Unnamed stream | A | 4 / 4, 4 / 4, 4 / 4 | Dam and Pump | Intermittent | Cold-water |
| Baileyville | 28.9 | Headwater tributary to Anderson Brook | A | 8 / 1,000 | HDD | Intermittent | Cold-water |

a/ State Designation - Based on Title 38 MRSA §465

A - 2nd highest classification. Must be of such quality that they are suitable for the designated uses of drinking water after disinfection; fishing; agriculture; recreation in and on the water; industrial process and cooling water supply; hydroelectric power generation, except as prohibited under Title 12, section 403; navigation; and as habitat for fish and other aquatic life. The habitat must be characterized as natural.

B - 3rd highest classification. Must be of such quality that they are suitable for the designated uses of drinking water supply after treatment; fishing; agriculture; recreation in and on the water; industrial process and cooling water supply; hydroelectric power generation, except as prohibited under Title 12, section 403; navigation; and as habitat for fish and other aquatic life. The habitat must be characterized as unimpaired.

C - 4th highest classification. Must be of such quality that they are suitable for the designated uses of drinking water supply after treatment; fishing; agriculture; recreation in and on the water; industrial process and cooling water supply; hydroelectric power generation, except as prohibited under Title 12, section 403; navigation; and as a habitat for fish and other aquatic life.

b/ Waterbody width determined from field measurements and aerial photograph interpretation.

c/ Fishery types were assigned based on habitat functionality observed during field assessment of proposed Pipeline crossings. Fishery habitat suitability assigned to waterbodies not sampled in the field were based on aerial photograph interpretation and MDIF&W fish stocking records.

HDD = Horizontal directional drill

crossed and avoids disturbance to riparian vegetation between HDD entry and exit locations. For this reason, HDD is considered to be a preferred crossing method for major waterbodies, especially those that are sensitive or for areas where there are sensitive environmental issues.

Downeast proposes to use HDD for a total of 26,030 feet of pipeline installation to avoid sensitive waterbodies and habitats such as vernal pools and wetlands. However, HDD is not technically feasible in some types of geologic environments such as glacial till, and it requires larger staging areas than other stream crossing methods. Downeast would need to conduct site-specific geotechnical investigations at all proposed HDD crossings to determine the feasibility of completing directional drills in these areas.

While the HDD method is often the preferred method for installing pipelines across sensitive resources, it is not without some environmental risk. An inadvertent release of drilling mud could enter the waterbody being crossed or the HDD installation could fail due to unfavorable geologic conditions and/or equipment failure.

The HDD method involves the circulation of a drilling mud to remove cuttings, stabilize the bore hole, and cool and lubricate the drill bit. Drilling mud is composed primarily of naturally occurring materials, such as water and bentonite clay, and a small percentage of other additives. During the drilling process, drilling mud can enter waterbodies through coarse, unconsolidated formations, such as sand and gravel, or through fractured rock formations. When an inadvertent release of drilling mud returns to the surface or enters a waterbody, it is referred to as a “frac-out.” A small release of drilling mud would likely dissipate and would not be detrimental to water quality, vegetation, fish, or wildlife. However, in larger quantities, the release of drilling mud into a waterbody could affect fisheries and vegetation; although impacts would likely be less than those associated with an open-cut crossing.

In the event of a frac-out incident that is accessible, Downeast has indicated that it would take the following appropriate measures:

- contain the location with straw bales such that the drilling fluid cannot migrate across the ground surface;
- excavate a small sump pit at the location and provide a means for the fluid to be returned to either the drilling operations or a disposal site (i.e., pump through a hose or into a tanker); and
- continue drilling operations and continue maintaining the integrity of the containment measures and monitoring the fluid returns as to ensure that no surface migration occurs.

Should the inadvertent release of drilling fluid occur at a location that is inaccessible or along the bed of a waterbody and into the water, the following appropriate procedures would be followed:

- ensure that all reasonable measures have been taken to re-establish fluid circulation, such as reducing fluid pressure during pilot hole drilling or vary drilling fluid properties in order to reduce frictional drag and pressure;

- continue drilling with the minimum amount of drilling fluid as required to penetrate the formation and successfully install the pipe; or
- if the amount of the release exceeds that which can be suitably contained with hand placed containment barriers, small collection sumps would be used for fluid removal and recycling.

Appendix E has been updated to include site-specific construction diagrams for each proposed HDD crossing showing the location of mud pits, pipe assembly areas, and all areas to be disturbed or cleared for construction. Downeast would conduct preconstruction geotechnical evaluations to ensure that HDD drilling operations as proposed are feasible. Downeast has also stated that it would prepare and submit contingency plans prior to construction

In the event that an HDD is unsuccessful and the HDD crossing has to be abandoned, the HDD pilot hole would be filled with an environmentally safe fluid (typically a mixture of bentonite clay and water) that would match the consistency of the surrounding subsurface. Downeast has indicated that as a final contingency, the pipeline would be installed using a traditional trenched crossing.

Downeast would obtain a Section 10 permit from the COE for work in navigable waterways and a Section 404 permit for placement of dredged or fill material into all waters of the United States, including wetlands. Downeast would also obtain an associated Section 401 Water Quality Certification from Maine DEP. A wastewater discharge permit would also be obtained from the state. The application to Maine DEP for a 401 Water Quality Certification was withdrawn by Downeast in November 2007; Downeast will resubmit its request following issuance of the final EIS. If any waterbody or wetland crossing plans are revised, Downeast would file the amended plans with the Secretary for review and written approval by the Director of OEP.

One of the largest HDD crossings proposed by Downeast is the 6,621-foot crossing of the St. Croix River and Magurrewock Stream Outlet between MP 14.1 and MP 15.3. The FWS, Maine DMR, Bureau of Indian Affairs (BIA), St. Croix International Waterway Commission, and the Passamaquoddy Tribe have expressed concerns about this crossing because of its proximity to the Moosehorn NWR boundary and Canadian border, the length of time to complete the HDD installation, the effects of noise and vibration on fish and wildlife, and impacts on tribal rights to the St. Croix River and islands within the St. Croix River.

Downeast has estimated that the HDD would take approximately 75 to 90 days to complete. This estimate is based on drilling 24 hours per day, with some reductions to 12 hours per day, to improve the likelihood of completing a successful drill and reducing the number of days that drilling would be required. The HDD is expected to occur between June and August; however, Downeast would coordinate with the Maine DMR to establish a construction schedule to avoid impacts on spawning fish. Because the HDD would be a minimum of 60 feet below the river bed, there should be minimal if any noise or vibration impacts on aquatic resources. Noise impacts from aboveground drilling operations at the entry and exit points are discussed in section 4.11.2.

The centerline path of the proposed St. Croix River HDD is, at its nearest points, 150 feet away from the Moosehorn NWR and 120 feet away from the Canadian border. The nearest point to Moosehorn NWR is at MP 15.1, where the boundary of the NWR is on the south side of the Maine Central Railroad right-of-way. The nearest point to Canada is at MP 14.5, where both the drill path and the border are in the St. Croix River. Impacts on the Moosehorn NWR and Canada would be avoided. All of the HDD except the last 500 feet is north of the Maine Central Railroad, which forms a barrier to the Moosehorn NWR to the south. The last 500 feet are west of the Moosehorn NWR boundary, and the HDD exit point is 900 feet west of the NWR boundary. The area where the drill path gets closest to the Canadian border is approximately 0.4 mile from the drill entry. Therefore, the drill would be very deep below the river, where an event, such as a release of drilling mud, reaching the surface would be very unlikely.

The only dewatering would be localized passive dewatering to keep any entry/exit HDD trench and work area dry for worker safety. Otherwise, the pipeline would be installed "in the wet" or within the groundwater table. In the locations where the pipeline is installed below the groundwater table, the groundwater levels are expected to stabilize back to equilibrium conditions around the pipeline immediately upon completion of construction. The construction and operation of the pipeline would not affect groundwater or surface water flows in the area of drilling and would not disrupt migration of spawning fish.

Water quality would be protected during HDD operations adjacent to the St. Croix River by adherence to Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* and its contractors' SPCC Plans based on the SPCC Plan template. All construction materials, fuels, and lubricants would be kept at least 100 feet away from the shoreline, and refueling of construction equipment would be conducted in upland areas 100 feet or more from the shore. The tailings and mud from the drilling activity would be pumped into temporary storage tanks and hauled to an approved disposal site.

We do not believe that the HDD would have any significant impact on any tribal rights to the use of the St. Croix River or the islands in the river at this location. Downeast has indicated that it has addressed the Passamaquoddy Tribe's concerns by designing the HDD path in a manner that avoids all islands in the St. Croix River, avoids encroachment on any designated Indian trust lands, and avoids disturbance to the river's ecosystem during construction and operation.

Downeast has provided us with information on successful direction drill projects of this length on other gas pipeline projects, and while we believe that HDD would avoid or minimize the significant impacts associated with this river crossing, we are concerned about the feasibility of the crossing. Downeast has evaluated the available geotechnical information relative to the subsurface conditions in the St. Croix River. Based on recent test borings for the international border crossing project, which is just north of the proposed HDD alignment, the subsurface conditions at the St. Croix HDD are expected to consist of stiff marine clay over dense glacial till and bedrock. Rock at the site is expected to consist of fresh schist/quartzite and granite, with top of rock likely ranging between 15 and 25 feet below ground surface. Due to the relatively shallow depth to rock and the length of the drill, the majority of the crossing is anticipated to be drilled in rock.

According to Downeast and based on the available subsurface information and the relatively stiff nature of the soil/rock profile at the site, an HDD crossing at this location is technically feasible and the subsurface conditions are considered to be favorable for this type of construction. In addition, the M&NE pipeline crossing of the St. Croix River at Baileyville was completed using HDD in similar subsurface conditions. Downeast has indicated that it would file a geotechnical feasibility assessment of the HDD location prior to requesting authorization to commence construction of its terminal or pipeline facilities and that the St. Croix HDD would be the first portion of the sendout pipeline constructed. Construction drawing Number DOW-E-HDD-15.0 Rev. No. A, included in Appendix E of this EIS, shows the St. Croix HDD location of mud pits, pipe assembly areas, and all areas to be disturbed or cleared for construction. FERC staff would review all supplemental information when filed, and would consult with resource agencies as appropriate during that review. However, to ensure that the HDD plan for the St. Croix River adequately addresses aquatic resources, **we recommend that:**

- **<u>Prior to construction of the pipeline facilities,</u> Downeast should consult with NOAA Fisheries on the proposed St. Croix HDD plan and file with the Secretary copies of NOAA Fisheries comments on the St. Croix HDD plan.**

Downeast's informal discussions with relevant resource agencies have indicated that the agencies are not comfortable with the potential environmental impacts of an open-cut crossing of the St. Croix River and thus would not support this construction method. Accordingly, Downeast is not proposing an open-cut crossing procedure as a contingency plan for the St. Croix River crossing. Prior to commencing the proposed HDD, Downeast would submit a geotechnical and environmental report for an alternate route inland of the proposed St. Croix HDD location for review and approval of the Director of OEP and relevant federal and state agencies. This alternate route would cross U.S. Route 1 and proceed to the Calais Industrial Track Railroad right-of-way owned by Pan Am Railways. The route would then travel along the southeast side of the railroad right-of-way between the St. Croix River and the Moosehorn NWR and continue on the railroad right-of-way to just beyond the city of Calais border near Baring, at which point the route would diverge south to the U.S. Route 1 right-of-way (see construction drawing Number DOW-E-HDD-15.0 Rev. No. A in Appendix E of this EIS). If the proposed St. Croix HDD fails, Downeast would need additional FERC approval before proceeding with any alternate HDD alignment.

The COE has requested that we include in this EIS an analysis of alternate crossing methods to the dam and pump method that Downeast proposes for the majority of the waterbody crossings to determine if there are practicable alternatives that would not require placement of fill in the waterways. The three alternatives that we are aware of that could be used that would not require excavation and temporary placement of fill within a waterway are a pipe bore, HDD, and the direct-pipe lay technique.

A pipe bore is the technique used to cross major roads, highways, and railroads. In a pipe bore, a pit would be excavated on both sides of the streambed to the elevation of the bottom of the pipeline bore with a width sufficient for the pipeline and casing to be pulled through. This technique is not typically used at stream crossings because of the need to excavate large pits on both sides of the streambed, creating more disturbances adjacent to the stream crossing. It would also have the potential for water intrusion into the pits requiring trench dewatering and discharge. For these reasons, we do not believe this is a practicable alternative to the methods proposed by Downeast.

The HDD technique is described in detail above. While it does prevent filling the stream, there are constructability, environmental, and economic issues that may not make it a reasonable or practicable alternative for all waterbody crossings.

Site constraints dictate whether HDD is the appropriate method to use. For HDD to be viable, stream subsurface geotechnical properties must be appropriate to conduct HDD.

HDD also requires extensive staging areas on both sides of the stream to set up the drilling equipment, mud pits, and a pipe assembly area. In many instances, we feel the additional clearing and the extensive mobilization could create more adverse environmental impacts than the dam and pump method proposed by Downeast.

In addition, HDD is a costlier technique due to the price of equipment, the setup and breakdown time and expense, the risk of setback or failure, and the relative paucity of trained operators. HDD generally is used to cross environmentally sensitive rivers or other habitats where the environmental effects of other crossing methods cannot be mitigated through other means. For these reasons, we do not believe that HDD is a practicable alternative for all the stream crossings along the sendout pipeline route. As discussed above, the dam and pump technique reduces the exposure of the waterbodies to erosion and sedimentation, and for most of the crossings can be accomplished within 24 to 48 hours.

In response to past concerns raised by federal, state, and local agencies regarding the potential impact of construction of pipeline projects in general, we developed our Procedures to provide guidelines for an acceptable level of protection for wetlands and waterbodies affected by pipeline projects. Our Procedures include requirements for pre-construction planning, environmental inspection, construction methods, sediment and erosion control, restoration, and post-construction maintenance. It includes provisions to handle stormwater and protection of waterbodies and wetlands from accidental spills of fuels or hazardous materials. Downeast has adopted our Procedures as part of its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*. We believe that using the measures detailed in our Procedures and applicable permits would minimize both short- and long-term impacts on water resources.

Lubricant, hydraulic fluid, and fuel spills from refueling construction equipment, fuel storage, or equipment failure in or near a waterbody could flow or migrate to the waterbody and immediately affect aquatic resources and contaminate the waterbody downstream of the release point. Downeast would follow the measures outlined in the project-specific SPCC Plans prepared by its contractors to minimize the potential impacts of spills of hazardous materials during construction in waterbodies.

Prior to being placed into service, the sendout pipeline would be hydrostatically tested to DOT standards, as listed in 49 CFR 192. The sendout pipeline (or sendout pipeline segments) would be pressurized to the design test pressure and the pressure would be maintained for a minimum of eight hours. If during the test period any leaks are detected, the leaks would be repaired and the test section re-pressurized until the DOT specifications are met.

Downeast would prepare a Hydrostatic Testing Plan to address the methods of water withdrawal and discharge. Approximately 6.1 million gallons of water would be required for hydrostatic testing of the entire 29.8-mile, 30-inch-diameter sendout pipeline. Downeast has stated that the sendout pipeline may be tested in more than one segment, allowing for reuse of some of the water and lowering the quantity needed. The water volume necessary would be dependent on the length of the segments tested. Downeast has identified the BUD as the source of hydrostatic test water through a direct connection to the fire hydrant system.

Downeast has indicated that the hydrostatic test water would be discharged to an unnamed creek at MP 17.5 or to the BUD sewer system at a rate of 1,400 to 2,800 gpm. Discharge of hydrostatic test water used to test the integrity of oil and gas facilities requires permitting from the Maine DEP. In addition, hydrostatic test waters that fall under the jurisdiction of the Maine DEP and that would be discharged into waters of the state would require a permit under the Maine PDES, as regulated by the CWA. The appropriate Section 401 Water Quality Certification and Section 404 permit must also be obtained prior to discharge of hydrostatic test water into surface waterbodies.

**Operations**

Operation of aboveground facilities associated with the proposed sendout pipeline, such as pig launchers and receivers, are not expected to affect water resources. Operational activities with the potential to impact water quality would be limited to maintenance of the permanent right-of-way and repair of the pipeline. To minimize impacts on water quality and riparian vegetation, Downeast would allow a riparian buffer at least 25 feet wide, as measured from the waterbody's mean high water mark, to permanently revegetate with native plant species across the entire right-of-way after construction is completed. However, trees greater than 15 feet tall, or deep-rooted shrubs that could damage the pipeline's protective coating, obscure periodic surveillance, or interfere with potential repairs, would not be allowed to grow within 15 feet of the pipeline. The frequency of the vegetation maintenance would depend upon the vegetation growth rate. This could lead to minor increases in stream temperature in these localized areas, but would not be expected to cause significant temperature increases farther downstream.

The Passamaquoddy Tribe expressed concern about operational impacts of the pipeline on the St. Croix River ecosystem, specifically potential changes to water temperature. Downeast has indicated that the sendout pipeline carries natural gas (not cryogenic gas) that is at a temperature of 41°F, which is near the ambient ground temperature of 45 to 55°F. The pipeline also would be located at least 10 feet below the bottom of the St. Croix River. Therefore, operation of the pipeline would have no temperature impact on the river ecosystem.

Because the sendout pipeline would be installed at a sufficient depth below the beds of waterbodies, exposure of the sendout pipeline is not expected. In the event that a pipeline anomaly (i.e., corrosion, dent, or rupture) is detected during routine inspections, pipeline excavation or replacement could be required within a waterbody. Impacts from these maintenance activities would be expected to be similar to those described for construction and would be subject to additional state and federal permitting. Therefore, operation of the project should not have a significant impact on water resources.

## 4.4 WETLANDS AND VEGETATION

This section describes the plant species and vegetative communities within the project area, construction and operational impacts on vegetative communities that would result from the project, and measures that would be taken to avoid, minimize, and mitigate for impacts on these communities. This section also covers photosynthesizing marine organisms such as phytoplankton and algae. The project has been designed to avoid significant impacts, and minimize and mitigate for unavoidable impacts on vegetation. Downeast would provide environmental training to construction and operations personnel, and EIs would monitor and enforce compliance with environmental permit conditions during construction and operations.

### 4.4.1 Wetlands

Wetlands are areas inundated or saturated by surface water or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions (33 CFR Part 328.3[b]). The Downeast LNG Project would cross coastal and freshwater wetlands, which are both regulated by the COE and Maine DEP under such regulations as the CWA, the Rivers and Harbors Act, and the Maine Natural Resources Protection Act (NRPA). Downeast submitted the NRPA and CWA Individual Permit applications in December 2006. The COE determined the applications under Section 10 of the Rivers and Harbors Act and under Section 404 of the CWA to be incomplete. The applications are not currently active for processing pending additional information to be submitted by Downeast. The application to Maine DEP for a 401 Water Quality Certificate under the NRPA was withdrawn by Downeast in November 2007; it will be resubmitted following issuance of the final EIS. The COE has noted that wetland delineations to support the revised permit applications must be performed according to the 1987 Corps of Engineers Wetland Delineation Manual (COE 1987) as well as the COE's 2012 Regional Supplement.

Coastal wetlands, as defined by Maine DEP, include estuarine intertidal and subtidal wetlands, which support vegetation tolerant of saline water. Intertidal wetlands are transitional vegetated areas along the shoreline that are periodically flooded by the tide. Subtidal habitats have substrates that are continuously flooded by tidal water. Vegetation commonly found in coastal wetlands consists of various seagrass species. Macroalgae, such as kelp species, are also commonly found in coastal wetlands. See section 4.4.2 for additional discussion of subtidal vegetation.

Freshwater wetlands found within the Downeast LNG Project area include riverine and palustrine habitats. Riverine wetland systems are supplied by waters from adjacent rivers or streams, while palustrine wetlands are supplied by precipitation, either as a surface or groundwater source. Freshwater wetlands in the project area can be generally classified as emergent, scrub-shrub, or forested. Emergent wetlands consist of erect, rooted, herbaceous plants that persist for most of the growing season. Scrub-shrub wetlands include areas dominated by woody vegetation less than 20 feet tall and are vegetated with true shrubs, young trees, and trees or shrubs that are small or stunted because of environmental conditions. Palustrine forested wetlands contain woody vegetation that is 20 feet or taller (Cowardin et al. 1979).

Wetland presence within the Downeast LNG Project boundaries was determined by the review of maps and field surveys using methods approved by the COE (COE 1987). The following sections describe the location of wetlands; potential impacts caused by construction and operation of project facilities (waterway for LNG marine traffic, LNG terminal, pier, and sendout pipeline); and mitigation for unavoidable wetland disturbance.

Vernal pools are shallow depressions that usually contain water for only part of the year and are often associated with forested wetlands. Vernal pools serve as essential breeding habitat for certain species of wildlife, including salamanders and frogs. Jurisdiction for vernal pools falls under both Maine DEP and COE regulations. As of September 2007, SVP habitat is protected by law under the NRPA. Accordingly, Maine DEP adopted Section 9 of Chapter 335, which provides SVP identification criteria and habitat management standards. Vernal pools that occur within COE-jurisdictional wetlands are reviewed under COE regulations. Vernal pools outside wetland boundaries or those deemed significant are reviewed under Maine DEP regulations. Vernal pools are considered "significant" by Maine DEP if they have a high habitat value, either because (1) a state-listed threatened or endangered species uses it to complete a critical part of its life history, or (2) there is a notable abundance of specific wildlife, such as blue-spotted salamander, wood frog, or fairy shrimp. SVP habitat includes the vernal pool itself and the area within a 250-foot radius of the spring or fall high water mark of the pool, which is considered critical terrestrial habitat.

Identification of vernal pools and SVPs within the terminal and sendout pipeline boundaries was completed in spring 2007 for the original pipeline alignment. Surveys for vernal pools along the rerouted segment of the pipeline were conducted in summer 2007. Assessment of SVP status was conducted in spring 2008. Results of the surveys are discussed in sections 4.4.1.2 and 4.4.1.3.

#### 4.4.1.1 Waterway for LNG Marine Traffic

There would be no impacts on freshwater wetlands as a result of normal LNG transit. Marine vegetation, including eelgrass, is discussed in section 4.4.2.

The Canadian Government prepared a study of anticipated impacts on Canadian lands resulting from LNG development in Passamaquoddy Bay, including wetland resources in the area of Grand Manan, Head Harbour Passage, Passamaquoddy Bay, and the St. Croix River near St. Andrews, New Brunswick. The study identified 30 freshwater wetlands greater than 24.7 acres in the lower St. Croix watershed. Eleven environmentally significant areas were identified from the New Brunswick Department of the Environment and Local Government and the Atlantic Canada Conservation Data Center databases. These areas are on Campobello Island (three areas), Grand Manan (two areas), and various public lands (six areas), and were listed as having special significance for wetlands and/or plants. The study concluded that the most likely potential effect to these wetland habitats from LNG development would be the accidental release of contaminants within the marine waterway from vessels transiting between the LNG port and the open ocean. We believe these impacts are not likely to occur as vessels transiting to the LNG terminal must comply with the Coast Guard regulations or they would not be granted access to the waterway.

### 4.4.1.2 LNG Terminal

Wetland presence at the proposed terminal location was determined by field surveys (underwater and terrestrial) and aerial photo interpretation conducted in 2005. Freshwater wetlands that are regulated by the Maine DEP and the COE were delineated at the terminal site in September 2005. At the proposed location of the pier, approximately 5.91 acres of subtidal wetland[10] and 0.7 acre of intertidal wetland[11] are present in the area where the pier would be located. Subtidal coastal wetlands support kelp of the species *Laminaria* (Mann 1973; Sebens 1986). Most of these macroalgae species are associated with hard structures or substrates, which are limited in the Downeast LNG Project area and therefore, large populations of macroalgae are limited as well. Intertidal areas of Passamoquoddy Bay support a variety of brown algae such as knotted wrack (*Ascophyllum* spp.), rockweed (*Fuscus* spp.), and bladderwrack (*Fuscus* spp.). Other species of macroalgae found in protected tidal pools or areas with high tidal and wave action, such as sea lettuce (*Ulva lactuca*), Irish moss (*Chondrus crispus*), and kelp (*Alaria esculenta)*, are not found at the LNG terminal site.

Beyond the coastal area, two freshwater wetlands were identified at the location of the proposed LNG terminal (see figure 4.4-1). These wetlands offer several important functions, including water storage, flood attenuation, groundwater recharge and discharge, water quality improvement, and wildlife habitat. Wetland 1 is a mix of forested and scrub-shrub vegetation. This wetland community bisects the LNG terminal site from an outlet to Passamaquoddy Bay near the northeastern boundary of the site, trending south and southeast across the site. Much of this wetland has been disturbed by historical agriculture use and timber harvest; however, the portions of the forested wetland that were not recently harvested are characterized by a well-established canopy, a relatively sparse shrub layer, and a sparse herbaceous layer. In general, a bryophyte layer composed of *Sphagnum* moss covers much of the ground in these relatively undisturbed areas. The harvested portions of the wetland are characterized by either dense shrub regeneration or relatively open areas with a well-developed herbaceous layer. The portion of the wetland that was in agricultural use until the 1960s is now a mix of dense shrub growth and relatively open wet meadow. Speckled alder (*Alnus incana*), choke cherry (*Prunus virginiana*), meadowsweet (*Spiraea alba* var. *latifolia*), and Virginia rose (*Rosa* cf *virginiana*) dominate the dense scrub-shrub area, whereas the wet meadow is characterized by herbaceous species such as foxtail (*Alopecurus* sp.), a sedge (*Scirpus microcarpus*), awl-fruited sedge (*Carex stipata*), tussock sedge (*C. stricta*), soft rush (*Juncus effusus*), flat-topped white aster (*Doellingeria umbellata*), bristly aster (*Symphyotrichum puniceum*), Canada goldenrod (*Solidago canadensis*), and woodland horsetail (*Equisetum sylvaticum*).

[10] Wetland is classified by the FWS as an estuarine, subtidal, unconsolidated bottom, subtidal wetland. The FWS classification code for this type of wetland is E1UBL.

[11] A portion of this wetland consisting of 0.11 acre is classified by the FWS as an estuarine, intertidal, unconsolidated shore, sand, regularly flooded wetland (FWS classification code E2US2N) and 0.58 acre of this wetland is classified by the FWS as an estuarine, intertidal, unconsolidated shore, aquatic bed, algal, regularly flooded wetland (FWS classification code of E2AB1N).

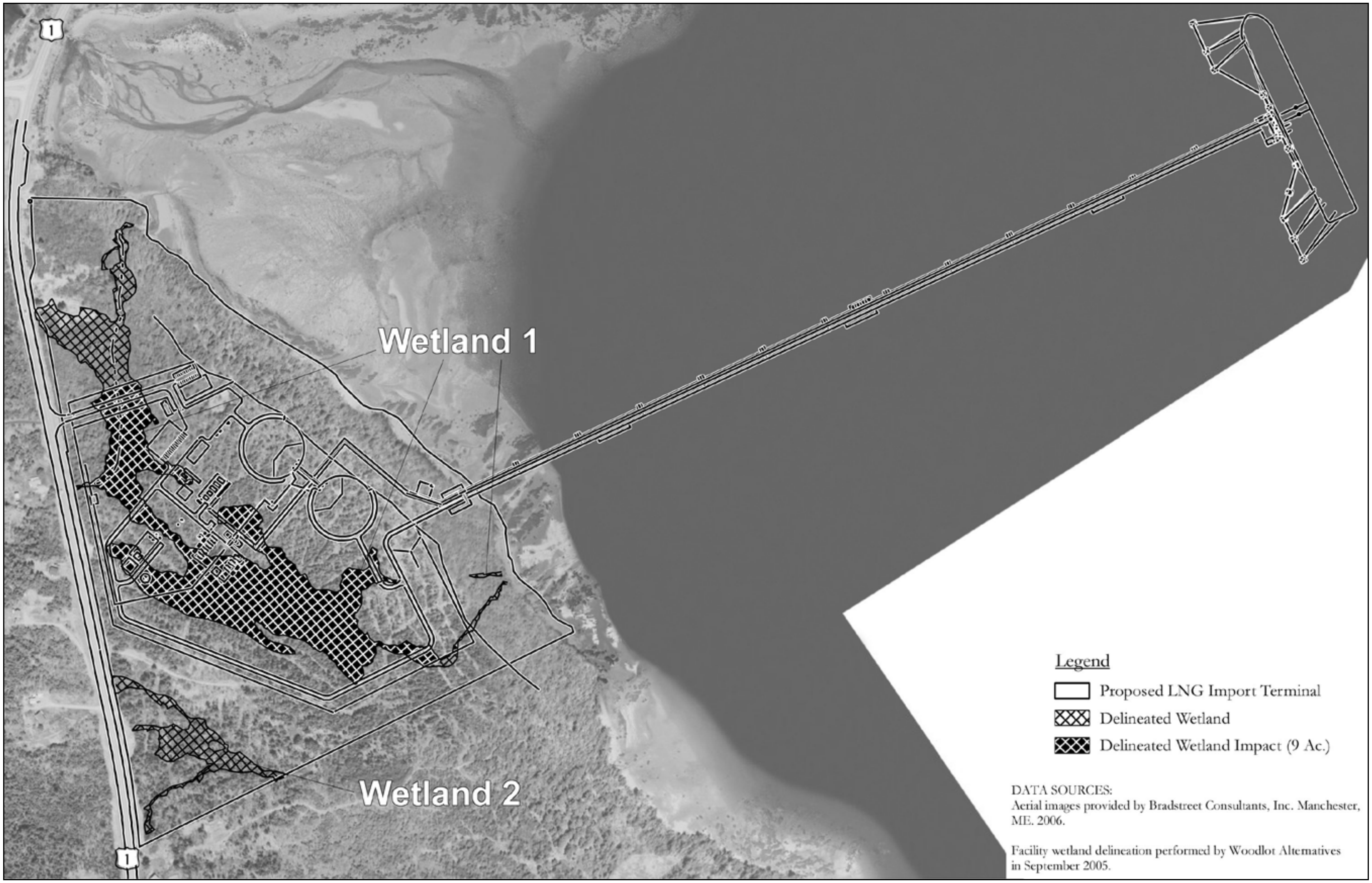


**Figure 4.4-1**
**Downeast LNG Project**
**LNG Terminal Wetlands**

Wetland 2 is a forested wetland in the southwestern corner of the site that extends south beyond the terminal property boundaries. As with Wetland 1, a portion of the overstory of this wetland was removed during timber harvesting. This wetland receives surface water flow from two culverts under U.S. Route 1, as well as groundwater discharge from hillside seeps. The overstory of Wetland 2 is comprised of white spruce (*Picea glauca*), balsam fir (*Abies balsamea*), northern white cedar (*Thuja occidentalis*), and yellow birch (*Betula alleghaniensis)*. Shrub species documented include speckled alder, pussy willow (*Salix discolor*), long-beaked willow (*Salix bebbiana*), meadowsweet, Virginia rose, red raspberry (*Rubus idaeus*), gray birch (*Betula populifolia*), quaking aspen (*Populus tremuloides*), green ash (*Fraxinus pennsylvanica*), larch (*Larix laricina*), northern white cedar, red maple (*Acer rubrum*), witherod (*Viburnum nudum*), and mountain holly (*Nemopanthus mucronatus*). Herbaceous species include flat-topped white aster, calico aster (*Symphyotrichum lateriflorum*), bristly aster, rough-stemmed goldenrod (*Solidago rugosa*), wild strawberry (*Fragaria virginiana*), red raspberry, dwarf raspberry (*Rubus pubescens*), fowl mannagrass (*Glyceria striata*), bluejoint (*Calamagrostis canadensis*), sedges (*C. flava, C. intumescens, C. scabrata*), wool-grass (*Scirpus cyperinus*), woodland horsetail, soft rush, sensitive fern (*Onoclea sensibilis*), cinnamon fern (*Osmunda cinnamomea*), and crested wood fern (*Dryopteris cristata*). A dense mat of *Sphagnum* moss dominates much of the forested wetland floor. Table 4.4.1.2-1 shows the acreage of disturbance for each wetland crossed.

TABLE 4.4.1.2-1

**Summary of Wetlands Affected by Construction and Operation**

| Wetland No. | Facility | Approx. Milepost | Wetland Classes | Permanent Impacts (acres) a/ | Construction Impacts (acres) b/ |
|---|---|---|---|---|---|
| | Terminal | | PFO/PSS | 9.00 | 9.00 |
| | Terminal | | E1UBL/E2US2N/E2AB1N | 0.10 | 0.10 |
| | **Total** | | | **9.10** | **9.10** |
| 1 | Pipeline | 0.04 | PSS | 0.01 | 0.12 |
| 2 | Pipeline | 0.39 | PFO | 0.22 | 0.46 |
| 3 | Pipeline | 0.64 | PSS | 0.08 | 0.15 |
| 4 | Pipeline | 0.80 | PFO/Stream | 0.03 | 0.05 |
| 5 | Pipeline | 1.02 | PSS/PFO | 0.37 | 0.63 |
| 13 | Pipeline | 1.95 | PFO | 0.05 | 0.07 |
| 14 | Pipeline | 2.02 | PFO/ STREAM | 0.06 | 0.15 |
| 15 | Pipeline | 2.10 | PFO/PEM | 0.17 | 0.32 |
| 16 | Pipeline | 2.16 | PFO | 0.04 | 0.05 |
| 17 | Pipeline | 2.25 | PFO | 0.01 | 0.01 |
| 18 | Pipeline | 2.54 | PFO | 0.51 | 1.02 |
| 18-1 | Pipeline | 2.73 | PFO | 0.03 | 0.06 |
| 21-1 | Pipeline | 3.32 | PSS | 0.03 | 0.03 |
| 21-2 | Pipeline | 3.40 | PSS | 0.10 | 0.13 |
| 25 | Pipeline | 4.15 | PEM/PSS/PFO/Stream | 0.05 | 0.08 |
| 6-36 | Pipeline | 4.44 | PFO/PEM | 0.00 | 0.04 |
| 26 | Pipeline | 4.60 | PFO/Stream | 0.03 | 0.05 |

TABLE 4.4.1.2-1

**Summary of Wetlands Affected by Construction and Operation**

| Wetland No. | Facility | Approx. Milepost | Wetland Classes | Permanent Impacts (acres) a/ | Construction Impacts (acres) b/ |
|---|---|---|---|---|---|
| 27-1 | Pipeline | 4.68 | PFO | 0.04 | 0.08 |
| 27-2 | Pipeline | 4.82 | PFO | 0.01 | 0.08 |
| 28 | Pipeline | 4.90 | PFO | 0.12 | 0.20 |
| 28-1 | Pipeline | 4.95 | PFO | 0.00 | 0.02 |
| 28-2 | Pipeline | 5.01 | PFO | 0.03 | 0.03 |
| 6-39 | Pipeline | 5.06 | PSS | 0.05 | 0.06 |
| 32 | Pipeline | 5.65 | PUB | 0.00 | 0.01 |
| 33 | Pipeline | 6.00 | PFO/PSS | 0.20 | 0.38 |
| 34 | Pipeline | 6.13 | PFO | 0.35 | 0.63 |
| 35 | Pipeline | 6.37 | PFO | 0.00 | 0.00 |
| 36 | Pipeline | 6.62 | PFO | 0.25 | 0.51 |
| 37 | Pipeline | 7.64 | PEM/PSS/PFO/ STREAM | 0.15 | 0.27 |
| 38 | Pipeline | 7.82 | PFO/PSS | 0.00 | 0.00 |
| 39 | Pipeline | 7.87 | PFO/PSS | 0.04 | 0.09 |
| 40 | Pipeline | 8.03 | PFO/PSS | 0.09 | 0.17 |
| 48-1 | Pipeline | 9.85 | PFO | 0.04 | 0.06 |
| 50 | Pipeline | 10.29 | PFO | 0.12 | 0.17 |
| 6-6 | Pipeline | 12.31 | PFO | 0.00 | 0.00 |
| 6-9 | Pipeline | 12.97 | PSS1 | 0.06 | 0.11 |
| 6-10 | Pipeline | 13.01 | PFO, PSS1, PEM | 0.14 | 0.29 |
| 6-11 | Pipeline | 13.89 | PSS1+4, PEM1 | 0.70 | 1.14 |
| 6-12 | Pipeline | 14.06 | PFO1 | 0.01 | 0.01 |
| 6-13 | Pipeline | 15.33 | PFO4+2 | 0.02 | 0.04 |
| 6-14 | Pipeline | 15.37 | PFO4 | 0.01 | 0.02 |
| 6-15 | Pipeline | 15.40 | PEM1 | 0.01 | 0.02 |
| 6-16 | Pipeline | 15.42 | PSS1 | 0.00 | 0.00 |
| 6-17 | Pipeline | 15.49 | PSS1, PFO4 | 0.00 | 0.01 |
| 6-18 | Pipeline | 15.53 | PSS1 | 0.00 | 0.01 |
| 6-19 | Pipeline | 15.56 | PFO1 | 0.00 | 0.03 |
| 6-20 | Pipeline | 15.78 | PFO1 | 0.03 | 0.06 |
| 6-21 | Pipeline | 15.85 | PFO1 | 0.08 | 0.14 |
| 6-22 | Pipeline | 15.94 | PFO | 0.01 | 0.08 |
| 6-23 | Pipeline | 16.04 | PFO1 | 0.10 | 0.29 |
| 6-41 | Pipeline | 16.11 | PFO | 0.00 | 0.01 |
| 6-42 | Pipeline | 16.36 | PSS | 0.73 | 1.46 |
| 6-25 | Pipeline | 16.46 | PFO1, PSS1, PEM | 0.46 | 0.90 |
| 6-26 | Pipeline | 16.66 | PFO1, PSS1 | 0.29 | 0.48 |
| 6-27 | Pipeline | 16.87 | PFO4, PSS1 | 0.00 | 0.00 |

TABLE 4.4.1.2-1

**Summary of Wetlands Affected by Construction and Operation**

| Wetland No. | Facility | Approx. Milepost | Wetland Classes | Permanent Impacts (acres) a/ | Construction Impacts (acres) b/ |
|---|---|---|---|---|---|
| 6-43 | Pipeline | 16.93 | PFO | 0.01 | 0.07 |
| 6-44 | Pipeline | 17.01 | PSS | 0.00 | 0.00 |
| 6-28 | Pipeline | 17.04 | PSS1, PEM1 | 0.01 | 0.03 |
| 6-29 | Pipeline | 17.10 | PSS1 | 0.11 | 0.13 |
| 6-30 | Pipeline | 17.23 | PFO4, PSS1, R2SB3 | 0.11 | 0.22 |
| 6-31 | Pipeline | 17.41 | PFO4, PSS1 | 0.13 | 0.25 |
| 6-32 | Pipeline | 17.49 | PSS1, PFO4 | 0.00 | 0.01 |
| 6-33 | Pipeline | 17.55 | PFO1, R2SB3 | 0.02 | 0.02 |
| 6-34 | Pipeline | 17.65 | PSS1, PEM1 | 0.04 | 0.04 |
| 95 | Pipeline | 17.70 | PEM/PSS/PFO | 0.03 | 0.04 |
| 98 | Pipeline | 18.23 | PFO | 0.04 | 0.04 |
| 99 | Pipeline | 18.26 | PFO/PEM/PSS | 0.02 | 0.05 |
| 100 | Pipeline | 18.37 | PEM/PSS/PFO/ STREAM | 0.15 | 0.25 |
| 101 | Pipeline | 18.45 | PEM | 0.00 | 0.00 |
| 102 | Pipeline | 18.52 | PFO | 0.10 | 0.15 |
| 103 | Pipeline | 18.58 | PFO/PSS/PEM | 0.03 | 0.07 |
| 104 | Pipeline | 18.73 | PFO/PEM | 0.04 | 0.06 |
| 105 | Pipeline | 18.79 | PEM | 0.00 | 0.00 |
| 106 | Pipeline | 18.81 | PFO/PSS | 0.04 | 0.04 |
| 107 | Pipeline | 18.82 | PEM/PSS/PFO | 0.00 | 0.00 |
| 108 | Pipeline | 18.84 | PEM | 0.02 | 0.03 |
| 109 | Pipeline | 19.02 | PFO/PEM | 0.11 | 0.21 |
| 110 | Pipeline | 19.11 | PEM/PFO | 0.04 | 0.11 |
| 111 | Pipeline | 19.21 | PEM | 0.00 | 0.01 |
| 112 | Pipeline | 19.52 | PEM/PFO | 0.05 | 0.09 |
| 113 | Pipeline | 19.60 | PFO/PSS/PEM | 0.15 | 0.24 |
| 114 | Pipeline | 19.67 | PEM/PSS | 0.08 | 0.17 |
| 115 | Pipeline | 20.04 | PEM | 0.00 | 0.01 |
| 116 | Pipeline | 20.14 | PEM | 0.02 | 0.15 |
| 117 | Pipeline | 20.60 | PEM | 0.00 | 0.00 |
| 118 | Pipeline | 20.63 | PEM | 0.08 | 0.15 |
| 119 | Pipeline | 20.73 | PEM/PFO | 0.48 | 0.92 |
| 120 | Pipeline | 21.05 | PFO | 0.01 | 0.02 |
| 121 | Pipeline | 21.17 | PEM | 0.00 | 0.01 |
| 122 | Pipeline | 21.23 | PEM/PFO | 0.04 | 0.08 |
| 125 | Pipeline | 21.52 | PEM | 0.00 | 0.00 |
| 126 | Pipeline | 21.55 | PEM | 0.00 | 0.00 |
| 127 | Pipeline | 21.78 | PSS/PEM/PFO | 0.02 | 0.02 |

TABLE 4.4.1.2-1

**Summary of Wetlands Affected by Construction and Operation**

| Wetland No. | Facility | Approx. Milepost | Wetland Classes | Permanent Impacts (acres) a/ | Construction Impacts (acres) b/ |
|---|---|---|---|---|---|
| 128 | Pipeline | 21.91 | PSS | 0.00 | 0.00 |
| 129 | Pipeline | 22.11 | PFO/PSS | 0.06 | 0.07 |
| 130 | Pipeline | 22.14 | PEM/PSS | 0.07 | 0.17 |
| 131 | Pipeline | 22.19 | PEM/PFO | 0.02 | 0.06 |
| 132 | Pipeline | 22.22 | PEM | 0.00 | 0.00 |
| 133 | Pipeline | 22.39 | PEM/PSS/PFO/STREAM | 0.58 | 1.06 |
| 134 | Pipeline | 22.80 | PFO | 0.01 | 0.02 |
| 135 | Pipeline | 23.07 | PFO | 0.06 | 0.08 |
| 136 | Pipeline | 23.47 | PEM/PFO | 0.38 | 0.70 |
| 137 | Pipeline | 23.75 | PFO | 0.04 | 0.04 |
| 139 | Pipeline | 24.43 | PSS/PUB | 0.13 | 0.13 |
| 140 | Pipeline | 24.59 | PEM/PFO | 0.55 | 1.04 |
| 141 | Pipeline | 24.96 | PSS/PFO | 0.04 | 0.09 |
| 144 | Pipeline | 25.57 | PSS/PFO | 0.09 | 0.17 |
| 145 | Pipeline | 25.65 | PFO/ STREAM | 0.09 | 0.14 |
| 146 | Pipeline | 25.84 | PSS/PFO/STREAM | 1.00 | 1.70 |
| 147 | Pipeline | 26.05 | PFO/PSS | 0.07 | 0.11 |
| 148 | Pipeline | 26.14 | PSS/PFO | 0.37 | 0.66 |
| 149 | Pipeline | 26.28 | PFO | 0.00 | 0.00 |
| 150 | Pipeline | 26.30 | PFO/PSS | 0.06 | 0.08 |
| | **Total** | | | **11.74** | **21.59** |
| | Access Roads | | | 0.00 | 0.14 |
| | Staging Areas c/ | | | 0.00 | 3.30 |
| | **Total** | | | **0.00** | **3.44** |
| | **Project Total** | | | **20.84** | **34.14** |

E1UBL – Estuarine Subtidal Unconsolidated Bottom
E2US2N – Estuarine Intertidal Unconsolidated Shore Sand Regularly Flooded
E2AB1N – Estuarine Intertidal Aquatic Bed Algal Regularly Flooded
PEM – Palustrine emergent
PFO – Palustrine forested
PSS – Palustrine scrub-shrub
PUB – Palustrine unconsolidated bottom
STREAM – Indicates stream also present
a/ Operational impacts are based on maintenance of a 30-foot-wide permanent right-of-way. This includes a 10-foot-wide strip (centered over the pipeline) that would be permanently maintained as herbaceous wetland during operation of the project. In addition, trees within 15 feet of the pipeline greater than 15 feet in height may be selectively cut and removed from the permanent right-of-way.
b/ Construction impacts for the pipeline are based on a 55- to 75-foot-wide right-of-way
c/ Includes ATWS, HDD ATWS, pipe laydown, and pipe storage areas.

Wetlands 1 and 2 offer several important functions and values. According to Attachment 12 of Downeast's NRPA Tier 3 Application, Wetland 1 provides eight functions, three of which are principal. The principal functions of Wetland 1 are floodwater alteration, sediment/toxicant reduction, and wildlife habitat. The secondary functions of Wetland 1 include groundwater discharge, fish habitat, nutrient removal, production export, and sediment/shoreline stabilization. Wetland 2 provides five functions, two of which are principal. The principal functions of Wetland 2 are floodwater alteration and wildlife habitat. The secondary functions of Wetland 2 are sediment/toxicant retention, nutrient removal, and sediment/shoreline stabilization. Neither wetland is notable for its wetland values, such as recreation, education, heritage value, visual quality, or endangered species habitat.

As described above, three coastal wetlands were identified in the location of the proposed pier structure (two intertidal and one tidal), totaling 6.6 acres. The direct impact on these habitats (about 0.1 acre) would be the surface area of solely the pier pilings themselves.

Construction methods for the pier are discussed in section 2.0 of this EIS. A combination of land-based and marine-based equipment would be used. Construction activities that could affect wetlands in the area include the installation of the pilings by vibration and drilling. Isolated areas would also be disturbed by barges anchoring during construction. No dredging activity is proposed. Temporary effects associated with these activities include sediment suspension and redistribution, turbidity plumes, and vegetation mortality. The use of land-based equipment in the nearshore, shallow waters would prevent significant suspension of sediments due to anchors and propeller wash. Vegetation in this area is sparse, and expected to rapidly re-colonize the disturbed areas. Additionally, the pier structure would provide habitat for rooted algae species and add functional complexity to this system.

Permanent adverse effects to wetlands include shading and potentially altered hydrodynamic processes in the vicinity of the pier. Shading would be minimal due to the open nature of the pier pilings and the height above mean high water (18.8 feet). Temporary shading impacts would also occur periodically while LNG vessels are docked at the pier. Placement of support structures in areas of flow can result in altered hydrodynamic processes (Harbeneau and Holley 2001; Dyhouse et al. 2003). Local current patterns could be influenced by the effect of the pier pilings deflecting flow or lowering its velocity, potentially resulting in the alteration of the area's normal sediment deposition pattern. Potential consequences could include shifts in the distributions of benthic fauna requiring specific grain-size classes. In an effort to minimize the potential for these risks, Downeast would continue its efforts to reduce the total area of submerged pier structure and/or design the pier to minimize impacts on the bay hydrodynamics.

Two freshwater wetlands, totaling 9.0 acres, are within the boundaries of the proposed terminal. These wetlands are characterized above. Downeast would attempt to minimize the impacts on these wetlands during the facility design. However, given the location of the wetlands and the need to design the facility to meet various building and safety codes, there is no practicable way to avoid disturbing these wetlands during construction and operation of this facility. Therefore, for the purpose of impact assessment, it has been assumed that all 9.0 acres would be permanently altered by clearing, grading, and filling. Downeast has stated that wetland soils would be stockpiled on-site and, where feasible, utilized to recreate wetlands disturbed during construction. Any unused stockpiles of wetland soils would be hauled off-site or used, if needed, for nearby wetland mitigation projects.

To mitigate for the unavoidable wetland alterations associated with the proposed terminal, Downeast is proposing a combination of preservation, enhancement, and restoration at off-site locations. Downeast and its consultants have met with the COE to discuss the jurisdictional determination of wetlands affected by project construction. Upon finalization of this jurisdictional determination and verification of vernal pools of special significance along the amended pipeline right-of-way, Downeast has stated that it would submit a revised mitigation and compensation plan to the regulatory agencies. The COE and Maine DEP are responsible for determining the areal extent necessary to satisfy compensation of the anticipated impacts on wetlands along with lost functions and values. However, Maine DEP generally provides the following compensation ratios: restoration – 1:1; enhancement – 1:1; and preservation – 8:1 (310 CMR 5C(5)). The COE acknowledges these ratios, but in many circumstances has required more mitigation than that required by Maine DEP. The 2008 COE/EPA mitigation rule would apply to the proposed project.[12] The COE New England Division also has mitigation guidance specific to the region, and the COE and Maine DEP have developed an In Lieu Fee program that can be used as compensatory mitigation for unavoidable impacts on wetland resources. The EPA expressed concern regarding the impact of active recreational vehicle trails on the functions and values of mitigation parcels, in addition to the potential need to improve stream crossings to reduce impacts on wildlife habitat. The Maine DIFW also noted the need to better define the existing roads and trails on the mitigation sites before plans are finalized. These issues will be addressed during the COE's, EPA's, and Maine DEP's review of the mitigation and compensation plan.

Compensation for direct impact on 0.11 acre of coastal wetlands would include enhancement of two coastal wetlands in Addison, Maine. The hydrology of these wetlands has been altered by adjacent roads and dikes, thus reducing the efficacy of tidal flooding and flushing. Downeast proposes to restore hydrology to these locations by excavating cuts into the dikes and replacing an undersized culvert. These modifications would restore natural hydrologic regimes to approximately 3.8 acres of saltmarsh and freshwater wetlands.

Downeast proposes to compensate for direct impact on 9.0 acres of inland wetland by establishing conservation easements for preservation of approximately 157 acres of wetlands and wetland buffer habitat near Calais, Maine. The 157 acres would include approximately 27 acres of wetlands and 35 acres of inland waterfowl and wading bird habitat. The remaining upland areas border high-value wetlands. Preservation of these areas would protect floodwater alteration, water quality, and wildlife habitat. The proposed compensation exceeds the Maine DEP required compensation ratio for preservation. Revised maps of these areas would be provided upon completion of mitigation and compensation planning with the COE, Maine DIFW, and Maine DEP.

In order to ensure that adequate wetlands compensation is provided to the satisfaction of the relevant agencies, **we recommend that:**

- **Downeast should continue consultation with the COE, EPA, and the Maine DIFW and DEP to finalize its wetland mitigation and compensation plan. Downeast should file the final plan with the Secretary, along with agency comments and applicable approvals, <u>prior to construction of the pipeline or LNG terminal facilities</u>.**

[12] Final Mitigation Rule for the Department of Defense, Department of the Army, Corps of Engineers, 33 CFR Parts 325 and 332; and U.S. Environmental Protection Agency, 40 CFR Part 230, Subpart J: Compensatory Mitigation for Losses of Aquatic Resources, effective June 8, 2008.

In addition to the measures required by our Procedures, Downeast would be required to comply with wetland permit conditions set forth by the COE and Maine DEP. As part of its review of the project, the COE would evaluate whether practicable alternatives have been evaluated to avoid wetland impacts on the maximum extent possible. Downeast also would comply with all rules and regulations pursuant to the CZMA of 1972, the CWA, and the Maine PDES Program for LNG terminal facilities installation and operation to avoid and minimize impacts on marine and shoreland environments. We believe that with implementation of the measures proposed by Downeast, including use of our Procedures, compensatory mitigation for permanent wetland impacts, and compliance with applicable regulations, impact on wetlands from construction and operation of the LNG terminal would not be significant.

No vernal pools, or state-listed sensitive species associated with vernal pool habitat, were identified at the LNG terminal location.

#### 4.4.1.3 Sendout Pipeline

Wetlands along the sendout pipeline route were delineated in July and August 2006, and September 2007, where landowner access was granted. In areas where property access was not granted, wetlands were identified through aerial photo interpretation. The location (by milepost) and character of each wetland crossed by the sendout pipeline are listed in table 4.4.1.2-1 along with the approximate acreage of wetland disturbance during project construction and operation.

Forested wetlands along the sendout pipeline are typically dominated by needle-leaved evergreen trees, balsam fir, red spruce (*Picea rubens*), northern white cedar, and larch, with subdominant broad-leaved deciduous hardwoods, paper birch (*Betula papyrifera*), red maple, and quaking aspen. Characteristic understory vegetation includes beaked hazelnut (*Corylus cornuta*), mountain holly, cinnamon fern, evergreen wood fern (*Dryopteris intermedia*), swamp dewberry (*Rubus hispidus*), and *Sphagnum* moss. Scrub-shrub wetlands are often dominated by meadowsweet, speckled alder, and steeplebush and have herbaceous vegetation that includes sensitive fern, pointed broom sedge (*C. scoparia*), and rattlesnake mannagrass (*Glyceria canadensis*). Emergent wetlands are characterized by rushes (*Scirpus* spp.), sedges (*C.* spp.), and broad-leaved cat-tail (*Typha latifolia*).

Potential vernal pools were identified during field surveys in 2006 and 2007 for the pipeline alignment. Field verification of vernal pools and SVPs occurred in spring of 2007 for vernal pools identified in 2006, and in spring of 2008 for vernal pools identified in 2007. Downeast identified 43 vernal pools, of which 10 were determined to meet the criteria listed in Maine DEP Rules Chapter 335 Section 9 to be classified as SVP as a result of the 2007 and 2008 spring surveys (table 4.4.1.3-1). Implications related to wildlife use of vernal pool habitat are discussed further in section 4.5.1.3 of this EIS.

Effects within the 250-foot buffer zone for each pool are shown in table 4.4.1.3-1. Under the Maine NRPA review standards, an applicant must maintain a minimum of 75 percent of the critical terrestrial habitat surrounding SVPs (as defined by the NRPA, Chapter 335, Section 9) as unfragmented forest with at least a partially closed canopy of overstory trees. According to the Maine DEP, impacts on the vernal pool depression and failure to meet these criteria would require compensatory mitigation. Downeast would maintain more than 75 percent of the upland forest habitat within the 250-foot buffer surrounding each SVP.

TABLE 4.4.1.3-1

**Vernal Pool Locations and Loss of Forested Land (acres) Associated with the Sendout Pipeline**

| | | 250' Buffer | | | 500' Buffer | | | 750' Buffer | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Appr. MP** | **Vernal Pool ID** | **Impact (acres)** | **Total Area (acres)** | **Percent of Buffer Impacted** | **Impact (acres)** | **Total Area (acres)** | **Percent of Buffer Impacted** | **Impact (acres)** | **Total Area (acres)** | **Percent of Buffer Impacted** |
| 1.1 | 6 | 0 | 4.3 | 0% | 0.4 | 17.0 | 3% | 1.0 | 38.8 | 3% |
| 1.2 | 7 | 0 | 3.8 | 0% | 0.3 | 15.9 | 2% | 0.8 | 38.1 | 2% |
| 1.2 | 8 a/ | 0 | 4.3 | 0% | 0 | 16.8 | 0% | 0.4 | 39.8 | 1% |
| 3.2 | 21S a/ | 0 | 5.8 | 0% | 0.7 | 20.3 | 4% | 2.0 | 43.7 | 5% |
| 3.2 | 21N a/ | 0 | 6.2 | 0% | 0.6 | 20.2 | 3% | 1.8 | 43.9 | 4% |
| 3.7 | 23 a/ | 0 | 5.4 | 0% | 1.1 | 19.5 | 6% | 2.3 | 40.3 | 6% |
| 4.9 | 20CF | 0.8 | 5.3 | 14% | 1.6 | 19.7 | 8% | 2.5 | 43.0 | 6% |
| 4.9 | 28 | 0 | 4.9 | 0% | 1.2 | 18.9 | 6% | 2.2 | 41.7 | 5% |
| 4.9 | 05BK | 0 | 4.6 | 0% | 1.2 | 18.2 | 6% | 2.1 | 40.7 | 5% |
| 4.9 | 06BK | 0.1 | 4.6 | 3% | 1.3 | 18.2 | 7% | 2.2 | 38.4 | 6% |
| 9.0 | 44 | 0 | 5.2 | 0% | 1.1 | 19.3 | 6% | 2.6 | 42.0 | 6% |
| 9.3 | 46 a/ | 0 | 4.1 | 0% | 0.8 | 18.0 | 5% | 2.0 | 41.4 | 5% |
| 9.5 | 48 | 0 | 4.3 | 0% | 1.2 | 17.6 | 7% | 2.5 | 39.4 | 6% |
| 9.7 | 17EA | 0.7 | 4.9 | 15% | 1.5 | 18.7 | 8% | 2.1 | 41.3 | 5% |
| 12.0 | 11EA | 0 | 4.8 | 0% | 0 | 18.2 | 0% | 0 | 40.8 | 0% |
| 12.0 | 01BK | 0 | 5.1 | 0% | 0 | 18.9 | 0% | 0 | 41.9 | 0% |
| 12.0 | 02BK | 0 | 5.1 | 0% | 0 | 18.8 | 0% | 0 | 41.7 | 0% |
| 12.0 | 03BK | 0 | 4.7 | 0% | 0 | 18.2 | 0% | 0 | 40.4 | 0% |
| 12.0 | 04BK | 0 | 4.9 | 0% | 0 | 18.5 | 0% | 0 | 41.5 | 0% |
| 12.1 | 12EA a/ | 0 | 6.5 | 0% | 0.1 | 21.6 | 0% | 0.7 | 45.7 | 1% |
| 12.8 | 13EA | 0 | 4.7 | 0% | 0.8 | 18.4 | 4% | 1.8 | 40.8 | 4% |
| 13.0 | 14EA a/ | 0.7 | 6.1 | 11% | 1.2 | 20.7 | 6% | 2.1 | 44.0 | 5% |
| 13.0 | 15EA a/ | 0.7 | 5.1 | 14% | 1.4 | 16.8 | 9% | 2.2 | 42.2 | 5% |
| 13.0 | 16EA | 0.9 | 4.6 | 19% | 2.0 | 16.2 | 13% | 2.8 | 36.1 | 8% |
| 15.2 | 01EA | 0 | 4.8 | 0% | 2.0 | 14.1 | 14% | 4.6 | 28.4 | 16% |
| 15.3 | 02EA | 0.5 | 4.8 | 10% | 4.6 | 18.3 | 25% | 7.3 | 38.9 | 19% |
| 15.3 | 03EA | 1.5 | 6.1 | 25% | 4.4 | 20.8 | 21% | 8.0 | 42.2 | 19% |
| 15.3 | 04EA | 1.4 | 7.9 | 17% | 3.6 | 24.4 | 15% | 7.3 | 47.2 | 16% |
| 15.3 | 05EA | 1.1 | 5.2 | 20% | 3.7 | 19.1 | 19% | 6.6 | 40.8 | 16% |
| 15.3 | 06EA | 1.3 | 6.6 | 20% | 2.7 | 20.7 | 13% | 6.7 | 41.0 | 16% |
| 15.3 | 07EA | 1.3 | 5.2 | 25% | 2.5 | 17.1 | 15% | 3.9 | 36.5 | 11% |
| 15.3 | 08EA | 0 | 5.9 | 0% | 0 | 19.6 | 0% | 1.3 | 37.2 | 4% |
| 15.3 | 09EA | 1.0 | 4.6 | 23% | 2.3 | 18.0 | 13% | 5.1 | 39.1 | 13% |
| 15.4 | 10EA | 0.9 | 5.1 | 19% | 4.2 | 18.5 | 23% | 6.2 | 36.4 | 17% |
| 15.4 | 07BK | 0.7 | 5.1 | 14% | 4.2 | 18.4 | 23% | 6.6 | 39.9 | 17% |
| 17.0 | 18EA | 0 | 2.6 | 0% | 0.9 | 10.7 | 9% | 1.9 | 23.1 | 8% |
| 17.1 | 19EA | 0 | 3.2 | 0% | 0.9 | 12.5 | 7% | 1.8 | 29.9 | 6% |
| 24.4 | 138 | 0 | 2.4 | 0% | 0.1 | 13.5 | 1% | 0.1 | 31.6 | 0% |
| 27.2 | 164W | 0 | 1.6 | 0% | 0 | 11.9 | 0% | 0 | 30.4 | 0% |
| 27.2 | 164E | 0 | 2.1 | 0% | 0 | 11.8 | 0% | 0 | 31.1 | 0% |
| 29.2 | 174 a/ | 0 | 5.6 | 0% | 0.6 | 18.1 | 3% | 1.2 | 40.7 | 3% |
| 29.6 | 178 | 0.9 | 2.7 | 33% | 1.3 | 13.6 | 10% | 1.6 | 33.7 | 5% |
| 29.8 | 179 a/ | 0 | 5.5 | 0% | 0.5 | 14.9 | 3% | 0.8 | 34.4 | 2% |

a/ denotes SVP

To minimize impacts on vernal pools, Downeast would use the guidelines approved by FERC, the COE, and the State of Maine for the M&NE Phase II Pipeline Project (*Soil Erosion and Sediment Controls Guidelines*). Additionally, Downeast would follow the *Best Management Practices, Conserving Pool-Breeding Amphibians in Residential and Commercial Developments in the Northeastern United States* (Calhoun and Klemens 2002) for development of site-specific construction activity and restoration plans. Restoration of the areas would include replication of the vernal pool depression using the same soils excavated, as well as replanting as much of the upland habitat buffer as possible while maintaining access to the right-of-way. The right-of-way width would be reduced to 55 feet through vernal pool areas. The duration of disturbance would be short-term, generally 24 to 48 hours. Sedimentation of the vernal pool areas would be minimized through use of erosion control devices. Maine DEP guidance for construction and mitigation for vernal pool disturbance includes:

- no disturbance within the vernal pool depression;
- maintain a minimum of 75 percent of the critical terrestrial habitat as unfragmented forest with at least a partly closed canopy of overstory trees to provide shade, deep litter, and woody debris;
- maintain or restore forest corridors connecting wetlands and SVPs;
- minimize forest floor disturbance; and
- maintain native understory vegetation and downed woody debris.

When considering the extended upland buffer from 250 to 500 feet from the pool, the relative amount of upland buffer affected by the project ranges between 0.22 and 9.68 percent, with an average of 4.84 percent project-wide. Effects within the area 250 feet to 500 feet from each pool and within the area 500 feet to 750 feet from each pool are shown in table 4.4.1.3-1. Maine DIFW has recommended to Maine DEP that if Downeast avoids and minimizes disturbance to less than 15 percent of the upland SVP habitat from 250 feet to 500 feet from the SVP, it has adequately minimized and avoided impacts on SVPs.

Field investigations and NWI mapping determined that approximately 26.6 acres of wetland would be affected during construction of the pipeline, of which approximately 14.2 acres would be permanently affected during operation. Table 4.4.1.2-1 shows the acreage of wetland impact due to the construction and operation of the terminal, pipeline, storage yards, workspaces, and access roads.

Wetlands offer several important functions, including water storage; flood attenuation; groundwater recharge and discharge; nutrient cycling; shoreline erosion control; water quality improvement by filtering out sediments and particles suspended in runoff water; breeding, nesting, and feeding habitat for a myriad of fish and wildlife species; habitat for numerous tree and plant species; and atmospheric maintenance by storing carbon instead of releasing it to the atmosphere as carbon dioxide. Some of the values of wetlands are providing sites for hunting, fishing, and trapping, and opportunities for recreation and aesthetic appreciation. Impacts from pipeline construction would be primarily temporary. Downeast would restore wetlands along the pipeline right-of-way to their original grade and hydrology; therefore, Downeast has not performed a detailed analysis of the functions and values of these wetlands. Downeast continues to consult with the COE and Maine DEP about project impacts on wetlands, mitigation measures, restoration, and post-construction monitoring, as described below. Downeast would provide a detailed assessment of wetland functions and values if required by the COE and/or Maine DEP.

To avoid or minimize impacts on wetlands, Downeast proposes to cross several wetlands using HDD technology; however, conventional trenching methods would be used to cross the majority of wetlands. Construction activities that would affect wetlands include vegetation clearing, grading, soil or sediment disturbance, and alteration of the local hydrology. Operational activities that would affect wetlands include periodic vegetation maintenance.

Vegetation clearing increases the volume and speed of precipitation that reaches the ground surface, thus increasing erosion potential. Lost vegetation also reduces the amount of water that is evapotranspired, resulting in higher water volumes in surface soils or in runoff streams. Most areas of cleared vegetation would be allowed to revegetate upon completion of construction; however, portions of the right-of-way would be periodically cut during operational maintenance. As shown on table 4.4.1.2-1, 27 acres of wetlands with forested area would be cleared during pipeline construction (including the right-of-way and associated work areas), of which 12.4 acres would be permanently converted to scrub-shrub/emergent wetland habitat during operations.

Grading activity would likely alter the existing surface water movement and distribution. Soil disturbance could disrupt a wetland’s capacity to convey surface water flow, retain flood waters, and control erosion. Failure to properly segregate topsoil over the pipeline trench line could result in the mixing of topsoil with the subsoil, which could affect the success of post-construction reestablishment and natural recruitment of native wetland vegetation. Rutting of soils from construction equipment could result in soil mixing, which could also affect success of post-construction restoration. Trenching during pipeline installation could penetrate impervious soil layers, drain perched water tables, and result in drier soil conditions that could inhibit the reestablishment of wetland vegetation. Disturbed soil in the trench could act as a conduit for subsurface water, effectively draining wetland water sources. Uncontrolled surface runoff from adjacent disturbed upland areas could transfer silt and sediment into off right-of-way wetlands.

In order to minimize or avoid many of these potential adverse effects, Downeast would implement its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*. These plans would include the following measures, among others, to minimize impact on wetlands:

- Hazardous materials, chemicals, fuels, and lubricating oils would not be stored within a wetland or within 100 feet of a wetland boundary.
- Concrete coating activities would not be performed within 100 feet of a wetland, unless the location is an existing industrial site designated for such use.
- All extra workspaces would be at least 50 feet from the wetland boundary.
- Construction equipment operating within wetland boundaries would be limited to that equipment necessary for clearing, excavation, pipe installation, backfilling, and restoration activities. All nonessential equipment would use upland access roads to the maximum extent practicable.
- Equipment operating within saturated wetlands would be low-ground-weight equipment or would operate from prefabricated construction mats.
- Temporary erosion and sediment control measures would be installed immediately after the initial disturbance of wetland soils and would be inspected and maintained regularly until final stabilization.
- Sediment controls would be installed across the construction right-of-way, as needed, within wetlands to contain trench spoil.
- Vegetation would be cut at ground level, leaving existing root systems in place to promote regrowth. Stumps would be removed from the trench line; stumps may be removed from the working side of the right-of-way if removal is required for safety concerns.

- The uppermost 12 inches of wetland topsoil would be segregated from the underlying subsoil in areas disturbed by trenching, except in areas with standing water or saturated soils, or where no topsoil layer is evident.
- Vegetation maintenance would not be conducted over the full width of the permanent right-of-way in wetlands. Shrubs and trees with roots that could compromise the integrity of pipeline coating may be selectively removed within 15 feet of the pipeline.
- Monitoring the success of wetland revegetation annually until wetland revegetation is successful.

Downeast would use a 55- to 65-foot-wide construction right-of-way in all of the wetlands crossed by the sendout pipeline. Any temporary timber matting used for wetland crossings that remains in the wetlands after construction would be considered a quantifiable discharge of dredged or fill materials that is subject to COE jurisdiction, unless it is within the footprint of impact (the right-of-way) already calculated. Downeast has stated that timber matting for the proposed sendout pipeline would be contained within the approved limits of the construction right-of-way and removed when access to the wetland is no longer required. The wetland would be restored to original grade and character.

The cleanup and final restoration phase is critical for mitigating long-term wetland impacts. During initial restoration, stored topsoil would be replaced over the trenchline, and wetland contours and drainage patterns would be restored approximately to original conditions. Surface rock and boulders removed from the trenchline during construction that are not replaced during backfill would be windrowed in upland areas or hauled off-site. Permanent slope breakers would be constructed to replace temporary erosion control devices in areas of sloped terrain. Once restoration of the substrate is complete, the right-of-way would be seeded with an annual ryegrass at a rate of 40 pounds per acre. This method, recommended by FERC and the NRCS for the M&NE Phase II and Phase IV filings, has been shown to effectively stabilize a site and serve as a nursery crop as the indigenous wetland vegetation reestablishes itself through natural succession.

A majority of the impacts on wetlands resulting from construction and operation of the proposed sendout pipeline facilities would be temporary. The COE and Maine DEP would require Downeast to provide mitigation for the temporary impacts associated with the sendout pipeline installation. The COE indicated in its July 2009 comment letter on the draft EIS that its position on mitigation for temporary impacts on linear projects has changed. Because it is likely to take several years for the right-of-way to revegetate, during this interim period, there would be a temporal loss of wetland habitat, functions, and values. Therefore, the COE would require that this temporary impact be addressed as part of the overall mitigation package. Downeast would conduct post-construction monitoring of all wetlands affected by construction to assess the condition of vegetation and the success of restoration until wetland revegetation is successful. Wetland revegetation shall be considered successful if the following criteria are met: the affected wetland satisfies the current federal definition for a wetland; vegetation is at least 80 percent of either the cover documented for the wetland prior to construction, or at least 80 percent of the cover in adjacent undisturbed wetland areas; if natural rather than active revegetation was used, the plant species composition is consistent with early successional wetland plant communities in that ecoregion; and invasive species and noxious weeds are absent, unless they are abundant in adjacent undisturbed wetland areas.

Temporary staging areas along the sendout pipeline route would be primarily in upland habitat, with some unavoidable exceptions. The ATWS at MP 15.6 is one such exception; it must be within a wetland at a turn in the alignment to properly construct the bend in the pipeline and push it under the railroad bed. In order to minimize any temporary impacts on wetlands from the staging areas, Downeast would implement its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*. In the event wetlands are encountered along those portions of the route that were not field delineated, Downeast would attempt to relocate the staging area out of wetlands.

All but one access road to be used for the construction of the sendout pipeline would consist of existing skidder roads previously constructed for timbering activities. Small, localized sections of these skidder roads may need to be widened; however, Downeast has stated that the access road improvements would not permanently impact any wetlands. Downeast has indicated that the existing skidder road between MP 5.2 and MP 6.2 already has affected wetland hydrology in the area by bifurcating the wetland complexes at MP 6.0 and MP 6.2. For this reason, the pipeline alignment has been sited north of the access road where there are sufficient wetland soils for restoration of wetland functions and values in the area.

We received comments from the COE in regards to Downeast's wetland construction procedures. The COE recommends that all wetland flagging be done no more than one to two months prior to construction and then re-inspected to ensure flagging is still in place. Any wetlands near staging areas and access roads should be reflagged prior to construction to ensure avoidance. We note that our Procedures require that wetland flagging be visible during construction. The COE also expressed concern for the processing of stones in the right-of-way, noting that they have required them to be replaced in wetlands during previous pipeline construction projects in the region. In addition, the COE generally recommends a minimum of five years of post-construction monitoring for projects of this nature. We note that the COE may require these specific mitigation measures as conditions of its Section 404 authorization.

We conclude that with implementation of the measures proposed by Downeast for pipeline construction and right-of-way restoration, which includes measures to avoid and minimize wetland impacts, as well as compliance with applicable regulations, impacts on wetlands from construction and operation of the sendout pipeline would not be significant.

FERC has also received several comments on the potential impacts of the Downeast LNG Project on the Moosehorn NWR, including federal and state agencies, wildlife advocacy groups, and individual citizens. In response, Downeast has rerouted the pipeline such that it completely avoids the Moosehorn NWR.

### 4.4.2 Vegetation

#### 4.4.2.1 Waterway for LNG Marine Traffic

**Marine Vegetation**

Marine and nearshore ecosystems support a variety of vegetation and photosynthesizing marine organisms such as phytoplankton, algae, and seagrasses. These organisms are primary producers and play an integral role in the health and integrity of this ecosystem. The majority of the intertidal zone is a mosaic of gravelly sand of varying grade sizes, fucoid-dominated ledge, and fairly homogenous pebbly gravel pavement that support little rooted vegetation.

Phytoplankton are microscopic photosynthesizing organisms that drift at or near the surface of the ocean. Phytoplankton exhibit seasonal density fluctuations, and regional studies show that phytoplankton peak in biomass annually in mid to late summer. Phytoplankton biomass growth is limited in the Project area by the interaction of light and water temperature, unlike most marine environments where nutrient availability limits phytoplankton growth. Section 4.5.2.2 of this EIS provides more detail on the function of phytoplankton in the zooplankton community. There would be no impact on marine vegetation from normal LNG vessel transit.

#### Terrestrial Vegetation

Island and shoreline vegetation along the waterway for LNG marine traffic is generally described as wooded with ledge rock outcrops. Dominant tree species include red spruce (*Picea rubens*), white spruce (*Picea glauca*), balsam fir (*Abies balsamea*), larch (*Larix laricina*), paper birch (*Betula papyrifera*), and red maple (*Acer rubrum*). Northern cedar (*Thurja occidentalis*) bogs are common. Normal LNG transit operations would have no adverse impact on these habitats.

#### Unique or Invasive Plant Communities

Seagrass beds, including eelgrass (*Zostera marina*) and widgeongrass (*Ruppia maritime*), found along coastal Maine waters provide valuable ecological functions, such as sediment stabilization, nutrient production and transport, and wildlife habitat. These grasses have exhibited a reduction in distribution throughout much of their range, and are therefore of significant concern.

Eelgrass is a keystone species in shallow estuarine and coastal marine habitats that provides high value tidal waterfowl and wading bird habitat. Eelgrass is federally protected under the CWA, which requires that eelgrass in certain areas that is destroyed by human activity be replaced or restored because of its role as essential fish habitat in the mid-Atlantic. Eelgrass beds are considered significant wildlife habitat by the Maine DIFW, with beds greater than 25 acres providing high value, and beds greater than or equal to 2.5 acres providing moderate value.

### 4.4.2.2 LNG Terminal

#### Marine Vegetation

Algal species found within the intertidal areas of the terminal site are primarily comprised of brown algae and rockweeds such as bladderwrack (*Fuscus* sp.) and knotted wrack (*Ascophyllum* spp.). Most of these algae species favor hard submerged structures and surfaces that are sparse in the terminal area.

Construction activities that may affect marine vegetation include sediment disturbance due to piling installation and the anchoring of barges. These activities would cause vegetation mortality in the immediate area of the activity, and would also cause some sediments to be suspended in the water column. Suspended sediments may cause a temporary and localized reduction in phytoplankton productivity due to reduced light penetration. During the construction and operation of the terminal, marine water withdrawals for hydrostatic testing, fire suppression systems testing, and ship ballast and hoteling may also have short-term and localized impacts on phytoplankton. The phytoplankton within the area of the terminal are not unique and any mortality caused by temporary impacts would likely be replaced through tidal action from the larger phytoplankton population within the Passamaquoddy Bay. Additional discussion of entrainment and impingement impacts on aquatic species is provided in section 4.5.2 of this EIS.

Temporary disturbance of bottom sediments may also release nutrients into the water column, which could cause an increase in phytoplankton production. The loss of light penetration due to increased turbidity and the potential release of increased nutrients due to disturbance are anticipated to be further dissipated through strong tidal exchange and tidal currents throughout the Passamaquoddy Bay.

Development of the pier and berthing facility would result in the permanent loss of a small quantity of algae as a result of pile installation and shading; however, the footprint of the pilings is relatively small, and the height and orientation of the pier would create a very limited shadow effect. The pilings of the pier would provide increased surface areas suitable for supporting shade-tolerant algae species. Although the increased shading beneath the pier and berthing facilities may cause a transition of algae species from shade-intolerant species to shade-tolerant species, no significant net loss of algal biomass is anticipated.

Eelgrass mapping completed by the Maine DMR in 2010 identified eelgrass within Mill Cove that was not present during previous mapping efforts in the 1990s (see figure 4.4-2). The proposed pier would cross about 350 feet of mapped eelgrass. In this area eelgrass could be directly impacted by placement of piles, temporary disturbance of bottom sediments during pile installation, and from shading during Project operation. Eelgrass is federally protected under the CWA and permanent impacts may require replacement or restoration of an equal area of eelgrass habitat. The actual area of impact would need to be determined based on a site-specific survey to verify the presence and extent of eelgrass in the area of the proposed pier. Therefore, **we recommend that:**

- **<u>Prior to construction of the LNG terminal facilities,</u> Downeast should conduct project-specific eelgrass mapping within Mill Cove to determine the presence and extent of eelgrass within areas that could be affected by the Project within Mill Cove. Results of the eelgrass mapping should be incorporated into compensatory mitigation planning, as needed. Downeast should file the results of the eelgrass mapping, and any resulting mitigation plan for potential impacts on eelgrass, including records of consultation with Maine DMR and NOAA Fisheries regarding mitigation, with the Secretary for review and written approval by the Director of OEP.**

### Terrestrial Vegetation

The dominant ecosystem on the 80-acre terminal site consists of forested upland habitats exhibiting varying degrees of age and composition due to past anthropogenic disturbances such as timber harvesting and agriculture. Agricultural fields abandoned since the 1960s are present in the northern section of the site, and are still relatively open though they are transitioning into wooded uplands and forested/scrub-shrub habitats through the process of natural succession. Remnant fencing, household dumps, and apple trees (*Malus sylvestris*) are still present in this area. The remainder of the site consists of forested/scrub-shrub wetlands (wetland vegetation communities are discussed in section 4.4.1).


**Legend**

Eel Grass (2010)*

*Maine Office of GIS/Maine DMR

0 250 500 1,000
Feet

## Figure 4.4-2

Downeast LNG Project
LNG Terminal Plot Plan
and Approximate Eel Grass Locations

N W E S

Document Path: P:\Downeast-3253\Team Information\GIS\Spatial\MXD\20140227_Eel_Grass_Locations.mxd

Upland forests in the northeastern portion of the site are characterized as an Aspen-Birch Woodland Forest Complex (Gawler and Cutko 2004). Deciduous tree species are prevalent, including paper birch, red maple, big-toothed aspen (*Populus grandidentata*), and choke cherry (*Prunus virginiana*). The shrub layer is dominated by such species as beaked hazelnut (*Corylus cornuta*), alternate-leaved dogwood (*Cornus alterniflora*), yellow birch (*Betula alleghaniensis*), red spruce, and choke cherry. The herbaceous layer is dominated by bunchberry (*Cornus canadensis*), wild sarsaparilla (*Aralia nudicaulis*), common speedwell (*Veronica officinalis*), lowbush blueberry (*Vaccinium angustifolium*), trailing arbutus (*Epigaea repens*), hawkweed (*Hieracium* sp.), and interrupted fern (*Osmunda claytoniana*).

Upland forests in the southeastern portion of the terminal site are characterized as spruce fir forest (Gawler and Cutko 2004). Dominant tree species include white spruce and red spruce. The shrub layer is dominated by such species as balsam fir (*Abies balsamea*), green alder (*Alnus viridis*), red spruce, paper birch, and yellow birch. A sparse herbaceous layer is present, dominated by such vegetation as Canada mayflower (*Maianthemum canadense*), twinflower (*Linnaea borealis*), wild sarsaparilla, bunchberry, and spruce and balsam fir seedlings.

Approximately 47 acres of the 80-acre LNG terminal site would be developed, including the aforementioned 9 acres of wetland and 38 acres of forest; an additional 8 acres of grassland would be temporarily disturbed during construction for use as ATWS. Within the terminal, vegetation would be cleared and mulched on-site and used as a temporary erosion control filter berm. Any remaining wood products would be either hauled off-site and sold as mulch or biomass, or placed in fill areas on the site where structural soil support is not needed. Downeast proposed to leave the remaining portion of the site, approximately 33 acres, undeveloped as a buffer. However, Downeast did not account for the forested areas in its hazard analyses. Therefore, in section 4.12.5, we have recommended that Downeast certify that all trees would be removed from the area between the vapor fences and the shoreline or demonstrate that the spacing of the trees, and any vegetation management plan, would prevent congested areas that could produce offsite overpressures above 1 psi. Given that recommendation, there is a possibility that the forested area visible in this figure would not be present after construction. Three off-site staging areas would be used during construction, temporarily disturbing approximately 8.0 acres of developed land and grassland. These sites would be in previously disturbed areas and would not require substantial clearing. Once construction is completed, these areas would be revegetated. Impact on terrestrial vegetation from construction and operation of the LNG terminal would include permanent conversion of 47 acres of vegetation to a developed site.

**Unique or Invasive Plant Communities**

Correspondence with Maine Natural Areas Program (Maine NAP 2006) indicates that no rare plant species or communities are present at the site of the proposed LNG terminal. Field investigation conducted by Downeast at the proposed LNG terminal site also indicated that no invasive plant species are present.

Eelgrass mapping completed by Maine DMR in 2010 identified eelgrass within Mill Cove that was not present during previous mapping efforts in the 1990s. The proposed pier would cross about 350 feet of mapped eelgrass. We have recommended that Downeast conduct project specific mapping within Mill Cove and determine potential presence and extent of eelgrass and need for mitigation for potential impacts (see section 4.4.2.2).

#### 4.4.2.3 Sendout Pipeline

The sendout pipeline route is predominantly covered by mature forest habitat characterized as spruce-fir, spruce-northern hardwoods, and white-pine mixed hardwoods (Gawler and Cutko 2004). Of these forest types, the spruce fir forest is the most prevalent. Other vegetation communities found along the sendout pipeline include early successional forests and maintained open areas such as open fields, residential, and agricultural land. In order to minimize impacts on vegetation communities, Downeast would implement its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*.

**Mature Forests**

The spruce-fir forest generally exhibits dense, closed canopies with sparse understory vegetation. Tree species commonly found include red spruce, balsam fir, northern white cedar, red maple, grey birch, paper birch, yellow birch, quaking aspen, big-toothed aspen, American beech, eastern white pine, white spruce, and eastern hemlock. In patches of less dense stands, shrub species consist primarily of striped maple (*Acer pensylvanicum*), mountain maple (*Acer spicata*), beaked hazelnut, mountain holly, low-bush blueberry, speckled alder, meadowsweet, winterberry, and red raspberry. Herbaceous plants found in the open canopy areas include Canada mayflower, wild sarsasparilla, bunchberry, wintergreen, starflower, sphagnum mosses (*Sphagnum* spp.), bracken fern (*Pteridium aquilinum*), and wood fern (*Dryopteris* spp.).

Spruce-northern hardwood stands occur as infrequent patches along the sendout pipeline route and are dominated by red spruce, sugar maple, red maple, American beech, and birch (*Betuala* spp.). Subdominate species include balsam fir and white pine. The sapling/shrub layer in this community is fairly well developed and composed of thick stands of striped maple and canopy species saplings. Other shrub associates include mountain maple, hobblebush (*Viburnum lantanoides*), beaked hazelnut, and mountain holly. Speckled alder, meadowsweet, and winterberry occur in wetter sites. The herbaceous layer is typically comprised of wood fern, tree seedlings, wild sarsaparilla, bristly sarsaparilla (*Aralia hispida*), bunchberry, and common wood-sorrel (*Oxalis montana*).

White pine-mixed hardwood forest is located along the northwestern portion of the pipeline route. This transition forest type includes white pine, balsam fir, red and sugar maple, white ash (*Fraxinus americanus*), birch, American beech, black cherry (*Prunus serotina*), and eastern hemlock. Common understory shrubs include tree saplings, low-bush blueberry, striped maple, and beaked hazelnut. Canada mayflower tends to dominate the herbaceous layer along with starflower, bunchberry, and tree seedlings.

**Early Successional Forest**

Several areas along the proposed sendout pipeline route have been cleared during commercial forestry activity. These communities are variable in their structure and composition based on the length of time following timber harvest. Early successional forests are dominated by pioneering tree species such as birch species, aspen species, and red maple, which would eventually be replaced through natural succession by spruce-fir forests typical for the region.

#### Maintained Open Areas

Typical plant species found in the open areas along the proposed right-of-way include introduced species such as timothy (*Phleum pretense*), clovers (*Trifolium* spp.), and fescues (*Festuca* spp.).

#### Construction and Operational Impacts

Construction of the sendout pipeline would affect an estimated 175.4 acres of forest, of which approximately 112.2 acres would be permanently converted into a non-forested vegetation community. The construction of the sendout pipeline also would affect an estimated 31.3 acres of open land (which includes developed land, agricultural land, and grassland), of which approximately 18.9 acres would be permanently maintained as right-of-way. Widening and improvement of access roads would permanently impact approximately 10.0 acres of upland habitat, of which 0.5 acre is forested and 9.5 acres are developed. Staging areas would temporarily impact approximately 13.5 acres of forest and 5.2 acres of open habitats (2.5 acres of developed, 1.1 acres of herbaceous, and 1.6 acres of agricultural lands). Project impacts on vegetative communities are detailed in table 4.7.1-1 of section 4.7 in this EIS.

The primary impact on vegetation would be the temporary and permanent clearing of vegetation along the pipeline right-of-way and access roads. Through upland areas, Downeast would create a 75-foot-wide construction right-of-way and maintain a 50-foot-wide right-of-way during operations. This would provide the minimum workspace necessary to permit staging, spoil stockpiling, assembly of the pipeline, and other activities necessary to building the pipeline.

Approximately 0.3 acre of recently harvested spruce-fir forest (plus 0.2 acre of right-of-way) would be cleared to construct one valve station for the sendout pipeline route. The effects would be permanent within the footprint of the station (total fenced area of 0.5 acre). One half of an acre would be permanently maintained for routine operations and maintenance.

All vegetation removal would be performed by hand or mechanical cutting. In areas of temporary impacts, rootstock and tree stumps would be left in place to encourage soil stability and natural revegetation. Discarded vegetation or other waste would be removed from the sendout pipeline right-of-way and properly disposed of in accordance with applicable permit conditions. Pre-established erosion controls would be installed immediately upon vegetation clearance and soil disturbance.

Downeast has stated that it would implement its Plan and *Soil Erosion and Sediment Control Guidelines* to ensure successful revegetation of the right-of-way. Upon completion of pipe installation, pre-existing grade would be restored and topsoil replaced. Within six working days of substrate restoration, the disturbed wetland areas of the right-of-way would be seeded with an annual ryegrass at a rate of 40 pounds per acre. This method, recommended by FERC and the NRCS for the M&NE Phase II and Phase IV filings, has been shown to effectively stabilize a site and serve as a nursery crop as the indigenous wetland vegetation reestablishes itself through natural succession. The permanent right-of-way seed mixture specified in table 6 of M&NE's Guidelines would be applied to most upland areas of the right-of-way. A permanent right-of-way would be maintained to permit access for routine on-site corridor patrols and emergency repairs, and to facilitate visibility during aerial patrols. Vegetation removal within the 50-foot-wide permanent right-of-way would be conducted every three to five years. A 10-foot-wide area directly over the pipeline would be mowed on an annual basis. There are no plans to utilize herbicides for right-of-way maintenance.

Varied effects are associated with the thinning and removal of vegetation, as this alters the structure and function of the vegetated community and associated wildlife habitats. The removal of mature forest vegetation could have prolonged effects, as forested vegetative communities are typically complex and take a longer period of time to regenerate to pre-existing conditions following a disturbance. Habitat characteristics may be lost or transitioned into a different habitat type, such as the transition of forested land into scrub-shrub and graminoid vegetated communities. The permanent right-of-way would fragment intact forest stands. To mitigate forest fragmentation, Downeast has collocated the pipeline, to the most practical extent possible, along existing rights-of-way. Clearing of vegetation along the right-of-way may also increase the impacts of erosion and solar heat as the loss of deep rooted vegetation would destabilize soils and the loss of shade would increase exposure to the sun. Vegetative disturbance may also increase the exposure of wind to some trees and increase the occurrence of blow downs. In addition, many invasive plant species are pioneer species adapt to establishing immediately following a disturbance. Forest disturbance may also produce positive effects, such as diversifying available habitats, increasing species diversity, and encouraging the growth of shade intolerant plant species.

All construction work areas would be monitored by Downeast for revegetation and restoration success. Inspections would be conducted at each of the following periods:

1. upon completion of initial regrading, stabilization, and reseeding;
2. at the beginning and latter parts of the first full growing season; and
3. during the second growing season.

FERC representatives would conduct restoration inspections in the spring following construction to verify revegetation success, as well as follow-up inspections as appropriate. We believe that with the implementation of Downeast's proposed measures for pipeline construction and right-of-way restoration, construction and operation of the sendout pipeline would not significantly impact vegetation.

**Unique or Invasive Plant Communities**

Correspondence with Maine NAP indicates that rare and unique plant communities are present within 4.0 miles of the proposed right-of-way, but would not be affected by construction. These communities are discussed further in section 4.6 of this EIS. Two invasive plant species were documented in several places in the pipeline right-of-way during field surveys. Purple loosestrife (*Lythrum salicaria*) was documented in six herbaceous wetlands delineated in the pipeline right-of-way segment that abuts the existing EMEC powerline corridor. Alder-buckthorn (*Frangula alnus*) was identified in and adjacent to the right-of-way segment that would parallel Icehouse Road.

Under Executive Order 13112, federal agencies shall not authorize, fund, or carry out actions that are likely to cause or promote the introduction or spread of invasive species in the United States or elsewhere unless the agency has determined and made public its determination that the benefits of such actions clearly outweigh the potential harm caused by invasive species. Additionally, the agency must ensure all feasible and prudent measures to minimize risk of harm be taken in conjunction with the actions.

During installation, operation, and maintenance of the sendout pipeline, Downeast would primarily employ measures in the M&NE *Soil Erosion and Sediment Control Guidelines* to prevent introducing new invasive species and avoid encouraging the spread of undesirable species already present. The M&NE *Soil Erosion and Sediment Control Guidelines* provide permanent seeding requirements that would facilitate quick revegetation to prevent unwanted species from becoming established. Following construction and initial revegetation, a monitoring plan would be employed to ensure that invasive species have not out-competed desirable vegetation during the re-establishment phase. The following strategy of integrated invasive plant management would be incorporated into construction procedures at locations with known invasive plant occurrences.

During construction:

- Remove invasive plants that could be potentially spread by construction equipment or workers. Along access roads, invasive plants would be identified and controlled to avoid introducing them into weed-free sites.
- Obvious vegetative material would be removed from construction equipment before allowing it to enter a weed-free area.
- Gravel and fill would come from weed-free sources to avoid introducing weedy vegetation to construction sites.
- Vegetation and ground disturbance activities would be confined to that which is deemed necessary for pipeline installation.
- Only certified weed-free straw, mulch, fiber rolls, and sediment logs would be used for erosion and sediment control.
- Workers would be trained to identify invasive plants, informed of the importance of infestation prevention, and required to employ measures to minimize weed invasion.
- Along the pipeline right-of-way, individual plants or small patches would be removed to control establishment.

During restoration:

- Any soil amendments (if any) and mulches would be obtained from weed-free sources.
- Certified weed-free seed would be used.
- Seeding and planting operations and maintenance would be conducted in a manner to ensure vigorous growth of desirable vegetation and discourage weeds.
- Bare ground would be seeded as quickly as possible.
- Seeded sites would be monitored for weed infestation.
- Identified weeds at monitored sites would be treated in the first full growing season.
- Mulching can limit the amount of unwanted seed sources reaching bare soil.

After initial revegetation steps have been achieved, the sendout pipeline right-of-way would be monitored and undesirable vegetation would be treated for the life of the project. We believe that Downeast's implementation of its proposed integrated invasive plant management during construction, and its proposed monitoring following construction, would be adequate measures to control the spread of invasive plant communities and would comply with the intent of Executive Order 13112.

## 4.5 WILDLIFE AND AQUATIC RESOURCES

This section describes the existing terrestrial and aquatic wildlife, and fisheries that would be affected by the proposed Downeast LNG Project. Section 4.5.1 describes existing resources, impacts, and mitigations for terrestrial wildlife and their habitats, while section 4.5.2 describes existing resources, impacts and mitigations for aquatic wildlife along the proposed LNG marine traffic route, LNG terminal, and sendout pipeline. Species that are protected by federal or state regulations are discussed in section 4.6.

### 4.5.1 Terrestrial Wildlife

#### 4.5.1.1 Waterway for LNG Marine Traffic

LNG vessels coming to the Downeast LNG Terminal could potentially take two transit routes from the Gulf of Maine to the Pilot Station. One is east of Grand Manan Island and follows the VTS indicated on navigation charts (see appendix F, figures F-1 to F-10). The other route generally would follow the coast of Maine west of Grand Manan Island. Once at the Pilot Station, LNG vessels would travel through Head Harbour Passage, Western Passage, and Passamaquoddy Bay, ending in Mill Cove near the entrance to the St. Croix River.

Around Grand Manan Island, the tides range from 19 to 22 feet. The tide ranges progressively increase with latitude towards the Bay of Fundy. Typical terrestrial fauna include seabirds, shorebirds, gulls, and sea ducks. Marine fauna are discussed in section 4.5.2.

**Coastal and Marine Avifauna**

Many avian species that occur in Maine are migratory; these species typically rest and feed in areas in or near the proposed waterway for LNG marine traffic, among other areas in Maine, before beginning or continuing the fall migration. Migratory species are protected by the Migratory Bird Treaty Act (MBTA) of 1918, and include all common songbirds, waterfowl, shorebirds, hawks, owls, eagles, ravens, crows, native doves and pigeons, swifts, martins, swallows and others, in addition to their body parts (feathers, plumes, etc.), nests, and eggs.[13] A "take" under the MBTA is defined as "to pursue, hunt, shoot, wound, kill, trap, capture, or collect, or any attempt to carry out these activities."

Marine avifauna with potential to occur near the proposed LNG marine traffic route includes seabirds, shorebirds, gulls, and sea ducks. The Western Passage and the area just north of Campobello Island are important habitats for marine birds. Several species of arctic birds migrate to the Bay of Fundy, including the area north of Campobello Island in summer. Species that use these areas include northern gannets (*Morus bassanus*), Atlantic puffins (*Fratercula arctica*), common murres (*Uria aalge*), common terns (*Sterna hirundo*), Atlantic terns (*Sterna paradisaea*), black-legged kittiwakes (*Rissa tridactyla*) and razorbills (*Alca torda*) (SENES 2007). Shortly before high tide in summer, large numbers of gulls, particularly Bonaparte's gulls (*Larus philadelphia*), are attracted to an upwelling site that occurs within the LNG marine traffic route between Eastport and Deer Island (see appendix F, figure F-15).

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[13] A complete list of species protected by the MBTA is found at 50 CFR 10.13.

The Quoddy Region, the area within a line drawn from Point Lepreau on the north shore of the Bay of Fundy, south to the Grand Manan archipelago, and west to the Maine shore, is an area of intense biological activity (Harvey, J. 2004). The Quoddy Region is used as a wintering ground for many seabirds (e.g., dovekies, shearwaters, and Wilson's storm petrel) and waterfowl. Species such as scoters, common eiders (*Somateria mollissima*), and American black ducks (*Anas rubripes*) have been documented from Passamaquoddy Bay and the St. Croix Estuary (SENES 2007). Large rafts of marine birds could potentially occur at any time of the year in the Quoddy Region depending on the species.

The SENES Report (2007) states that 300 species of birds, many of which are migratory, inhabit the Canadian portion of the Quoddy Region during some part of the year, which suggests the global importance of this region. It notes that 100,000 to 1,000,000 birds travel through the Bay of Fundy during a single year. The study area is important for raptors such as the bald eagle, osprey, and peregrine falcon. The Wolf Islands, located east of Campobello Island, were identified as an important wintering ground for the harlequin duck with approximately 50 birds; White Head Island also accounts for another 25 birds. Grand Manan was identified as being renowned for its seabird populations. The colonies in Grand Manan's Long Island Bay include double-crested cormorant, common eider, herring gull, and various sandpipers and terns. The colonies of common eider in 2002 on Grand Manan were estimated at 2,763 to 5,237 pairs. Great blue herons were also noted to occur on Long Island.

The SENES Report (2007) notes that more than 9,300 acres of intertidal mud and sand flats occur in the inner Quoddy Region; these areas support diverse primary food types that are used by shorebirds, wading birds, and waterfowl. Mudflats of the upper Bay of Fundy serve as feeding and gathering grounds for much of the North American shorebird population during annual migrations. More than 278 acres of salt marsh occur in the inner Quoddy Region; these areas support nesting and migrant bird populations.

Ten major islands and a number of ledges that remain exposed at high tide are found near the waterway for LNG marine traffic; these islands provide nesting, foraging, and loafing habitats for nesting and migratory birds. Of these islands, Hardwood Island has the largest colony of great blue herons in the Bay of Fundy (47 nests in 1981) and is an important stopover point for migratory birds in the spring and fall. Dicks Island has harbored up to 400 pairs of eider. Islands in the area provide nesting sites for the bald eagle and osprey (SENES 2007).

<u>Seabirds</u>

In Chapter 335, Maine DEP defines seabirds as those birds that include colonial nesting waterbirds such as petrals, cormorants, terns, alcids, and eider. Maine DEP has defined the period from April 15 to August 31 as the nesting season on Maine nesting islands. Seabirds are likely to occur within the LNG waterway for marine traffic during this time, especially in an area of upwelling between Eastport and Deer Island.

Maine DIFW has identified significant wildlife habitats used by migratory birds for feeding, breeding, and roosting activities. Significant wildlife habitats are regulated under the NRPA Chapter 335 (38 MRSA § 480-B [10]), which is administered by the Maine DEP. Significant wildlife habitats occur within and near the waterway for LNG marine traffic, as depicted in Appendix F, figures F-14 and F-15. These include inland waterfowl and wading bird habitat

(IWWH), tidal waterfowl and wading bird habitat (TWWH), shorebird nesting, feeding and staging areas (Shorebird Areas), and seabird nesting islands.

Inland Waterfowl and Wading Bird Habitat

The IWWH is ranked as high or moderate value based on observed species use, dominant wetland type, and the diversity, size, and interspersion of wetland types. In general, the state's mapped IWWH includes the wetland complex and a 250-foot upland habitat buffer zone. IWWHs that have been mapped, but not evaluated, are classified as unknown or indeterminate. Protection is afforded to those habitats ranking moderate or high value. Two IWWHs occur near the LNG transit route immediately south of Gleason Cove in the Town of Perry.

Tidal Waterfowl and Wading Bird Habitat

Maine DIFW considers four distinct TWWH types as high or moderate value based on aerial extent, including aquatic beds, reefs, emergent wetlands, and mudflats. Along the LNG transit route from Robbinston to Eastport TWWH occurs in most coastal areas.

Shorebird Areas

Under Chapter 335, Maine DEP defines shorebirds to include members of the families *Scolopacidae*, *Charadriidae*, and *Haematopodidae* (e.g., sandpipers and plovers). High or moderate value Shorebird Areas and the 250-foot buffer zone surrounding those areas are considered to be Shorebird Areas. These protected areas are used for feeding, roosting, or staging prior to migration. Feeding and staging areas provide foods that enable shorebirds to develop fat reserves that are essential for long-distance migration. Staging habitats include those sites with suitable resting areas for shorebirds during high tide when food resources are unavailable. Generally, Shorebird Areas are coves that experience highly variable tidal cycles and that tend to be quiet, protected sites for feeding and roosting.

A total of six Shorebird Areas occur along the waterway for LNG marine traffic. These areas are located in Mill Cove, Gleason Cove, Pleasant Point, Carrying Place Cove, Carlow Island, and Broad Cove, as depicted in appendix F, figures F-14 and F-15. With the exception of Mill Cove, which provides only shorebird feeding habitat, all other Shorebird Areas provide both feeding and roosting habitats.

The SENES Report (2007) identifies 25 environmentally significant areas near the waterway for LNG marine traffic in Canada. One area occurs at the northern edge of Campobello Island, and is significant for vertebrate fauna. A second environmentally significant area occurs on Indian Island, located northeast of Eastport, and is significant for vertebrate fauna. Other environmentally significant areas occur near St. Andrews (significant for fisheries), near the West Isles, east of Deer Island (significant for fisheries and vertebrate fauna), and in Roosevelt Campobello International Park near Liberty Point, which are significant for vascular plants and invertebrate fauna.

**Impacts on Coastal and Marine Avifauna**

Coastal and marine avifauna may be indirectly or directly affected by disturbance from LNG marine vessel traffic. Birds are much less mobile during nesting and many marine species nest in colonies on offshore and inshore islands where they are vulnerable to disturbance (e.g., harassment). Vessels transporting LNG to the proposed terminal would pass by a single known colonial nesting area, located 2 miles from the vessel route on Spectacle Island (see figure F-15 of Appendix F) and separated from the LNG transit route by Moose Island. Seabirds nesting on Spectacle Island are unlikely to be affected by normal passage of LNG vessels. Because known sea and shorebird nesting occurrence near the waterway for LNG marine traffic is low, it is anticipated that proposed LNG marine vessel operations would not adversely affect these species.

Operation of the proposed project may directly affect birds due to increased vessel traffic in Passamaquoddy Bay. Birds are known to collide with a variety of man-made structures subsequently causing disorientation, injury, and often death. Bird strikes with marine vessels are not well reported; it is hypothesized that these events are infrequent based on information in Hebert and Reese (1995) and Trapp (1998). One incident (Bagg 1965, as cited in Hebert et al., 1995) documented that approximately 150 to 175 birds landed on the deck of a vessel off the New Jersey coast in April of 1965. Mortality was limited to 23 Cape May warblers (*Dendroica tigrina*), which were assumed to have collided with the vessel's infrastructure. Exhaustion consequential to low energy reserves during long migratory flights can be a contributing factor to bird collisions with man-made structures. Birds flying during the day near the water's surface while feeding are expected to be able to avoid an LNG vessel that is docked or traveling in the waterway. However, birds that migrate at night may collide with a vessel during periods of low visibility. Nonetheless, bird collisions with LNG vessels are predicted to be low considering the existing anthropogenic factors in the landscape that are expected to create hazards for birds. The long-term effect of bird and vessel collisions is not predicted to have measurable consequences to bird populations in the project area.

The potential for shoreline erosion and subsequent impact on avian habitats that occur along the waterway for LNG marine traffic is low because, although speed of the vessel would be at the discretion of the ship's Captain, attending pilot, and any operational parameters established by the Coast Guard Captain of the Port, vessels would typically travel at speeds of 10 knots or less. LNG vessel traffic is not expected to have adverse impacts on coastal or marine avifauna or its habitat, because it would not contribute to adverse degradation or disturbance to bird habitat or bird populations during normal operation.

#### 4.5.1.2 LNG Terminal

The terminal site is located on approximately 80 acres between U.S. Route 1 and Passamaquoddy Bay, with its pier extending into the Passamaquoddy Bay in Robbinston, Maine. Wildlife species that use habitats associated with the proposed terminal include coastal wildlife, such as shorebirds and marine mammals, and terrestrial wildlife associated with the onshore terminal facilities. Marine mammals are discussed in section 4.5.2 of this EIS.

**Coastal Avifauna**

Coastal avifauna depend on wetlands and shoreline habitats for feeding, refuge, and loafing habitats. Field investigations were conducted in accordance with Maine DIFW protocols for shorebird presence along shoreline areas in July and September of 2006. Species with high frequency of occurrence included greater yellowlegs (*Tringa melanoleuca*) and lesser yellowlegs (*Tringa flavipes*); however, species observed in the greatest number were lesser yellowlegs and semipalmated plover (*Charadrius semipalmatus*). These species observations were consistent with data collected by Maine DIFW over a 6-year period from 1991 to 1997 (Maine DIFW 2006a). Alcids, such as razorbills and puffins, are associated with isolated rocky islands in the Gulf of Maine, and are not likely to occur near the shores of Mill Cove. Table 4.5.1.2-1 lists birds that were observed during the field surveys of Mill Cove conducted by Downeast in 2006 and 2007. Other birds such as gulls and cormorants were observed roosting on a weir in Mill Cove. Birds were observed foraging in the middle of Mill Cove, in the outlet to the bay, and around the standing water in the mudflats. Shorebird feeding and staging were observed in the northern portion of Mill Cove, more than 1,500 feet from the proposed pier. Approximately 9.6 acres of coastal avian habitats would be affected by the operation of the terminal and pier facility (table 4.5.1.2-2).

TABLE 4.5.1.2-1

**Summary of Mill Cove Shorebird Observations**

| Species | 2006 | | | | 2007 | | |
|---|---|---|---|---|---|---|---|
| | July (n=4 obs) | Aug (n=4 obs) | Sept (n=2 obs) | Total 2006 | July (n=2 obs) | Aug (n=6 obs) | Total 2007 |
| Black-bellied Plover | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Semipalmated Plover | 23 | 63 | 0 | 86 | 0 | 54 | 54 |
| Greater Yellowlegs | 16 | 10 | 18 | 44 | 2 | 20 | 22 |
| Lesser Yellowlegs | 81 | 43 | 6 | 130 | 15 | 58 | 73 |
| Solitary Sandpiper | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| Willet | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| Spotted Sandpiper | 0 | 0 | 0 | 0 | 1 | 14 | 15 |
| Sanderling | 0 | 2 | 0 | 2 | 2 | 1 | 3 |
| Semipalmated Sandpiper | 19 | 17 | 0 | 36 | 7 | 26 | 33 |
| Least Sandpiper | 14 | 5 | 0 | 19 | 4 | 26 | 30 |
| Western Sandpiper | 8 | 7 | 0 | 15 | 0 | 0 | 0 |
| White-rumped Sandpiper | 0 | 0 | 0 | 0 | 0 | 2 | 2 |
| Peep spp. | 0 | 1 | 0 | 1 | 0 | 27 | 27 |
| Short-billed Dowitcher | 11 | 0 | 0 | 11 | 0 | 0 | 0 |
| **Total Individuals** | **172** | **148** | **24** | **344** | **31** | **230** | **261** |

The common tern (*Sterna hirundo*), which is associated with large expanses of open water in the Downeast LNG Project area, is listed as a FWS bird of conservation concern (FWS 2002). This species was observed flying over Passamaquoddy Bay during shorebird surveys at the site.

TABLE 4.5.1.2-2

**Acres of Impact on Terrestrial Wildlife Habitats by Construction and Operation of the LNG Terminal**

| Facility | Forest Land | | Submerged Land | | Wetlands | | Agricultural | | Grassland | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Con. | Op. | Con. | Op. | Con. | Op. | Con. | Op. | Con. | Op. | Con. | Op. |
| LNG Terminal a/ | 38.0 | 38.0 | 0 | 0 | 9.0 | 9.0 | 0 | 0 | 0 | 0 | 47.0 | 47.0 |
| Off-site laydown areas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 8.0 | 0 | 8.0 | 0.0 |
| Pier trestle and unloading platform | 0 | 0 | 3.6 | 3.6 | 9.6 | 9.6 | 0 | 0 | 0 | 0 | 13.2 | 13.2 |
| **Total LNG Terminal** | **38.0** | **38.0** | **3.6** | **3.6** | **18.6** | **18.6** | **0** | **0** | **8.0** | **0** | **68.2** | **60.2** |

a/ Includes the pig launching facility inside the terminal property.

Night-time construction of the proposed terminal and pier would require sufficient lighting for both land-based and barge-based methods. Lighting during nighttime construction would create an atypical environment for nocturnal birds, possibly making the area surrounding the terminal and pier unsuitable for certain activities such as hiding or locating prey. Operation of the proposed terminal would continue to have long-term night-lighting effects, but to a less intense level than that for any nighttime construction. To mitigate impacts on nocturnal species, Downeast would strategically locate light fixtures to minimize light pollution beyond the terminal area. Fixtures would be avoided on top of tall structures. Down-directed lighting would be used to reduce night-lighting effects to animals in the terminal area. Fixtures would point down and at angles to minimize glare beyond the terminal area. Perimeter lighting would be kept as low as possible to allow security camera operation without creating a nuisance to neighbors. High-intensity discharge (HID) fixtures would be used where possible. Additionally, low-glare yellow light bulbs versus white-glare bulbs would be used where feasible. To reduce lighting effects, Downeast would limit exterior lighting at the terminal and its associated pier to those levels mandated by the Coast Guard and necessary for maintaining human health and safety.

The electrical system would be designed in accordance with the National Electrical Code (NEC) and located to satisfy criteria established by the Coast Guard, the FERC, Maine regulatory authorities, federal and state occupational safety regulations, and Downeast LNG safety policies. However, lighting requirements are contingent upon Coast Guard review of safety lighting upon completion of construction. Using lighting methods that Downeast has proposed, the effects of lighting in the LNG terminal facilities are unlikely to significantly affect shorebirds and terrestrial species. Section 4.5.2 of this EIS discusses the impacts of LNG vessel water withdrawals and discharges during operation of the LNG terminal.

<u>Significant Wildlife Habitat</u>

The proposed pier would traverse an 800-foot section of TWWH and its 250-foot buffer zone that is regulated by Maine DEP, Bureau of Land and Water Quality. The pier would also traverse a 250-foot section of state-designated Shorebird Area that extends across the mouth of Mill Cove to approximately 0.5 mile south of the proposed terminal. The Mill Cove Shorebird Area includes a 75-foot protective buffer zone. These significant wildlife habitats total 0.4 and 0.6 acres, respectively, as shown in figures M-1 and M-2 of appendix M.

Waterfowl, wading birds, and shorebirds are expected to avoid this portion of Mill Cove while construction activities occur. Areas shaded by the pier would be unavailable to feeding shorebirds due to behavioral avoidance of overhead structures. The berthing facility would be located in deeper waters beyond these habitats; therefore, operational effects would be limited to noise, night safety lighting, and shading, which act to reduce both the quantity and quality of available shorebird habitat in Mill Cove.

Maine DIFW indicated specific concerns regarding effects from construction of the proposed project on shorebirds and shorebird habitat. In a letter dated April 2, 2007, Maine DIFW noted that Downeast's 2006 and 2007 shorebird surveys found most shorebirds using the north end of Mill Cove near the culvert at U.S. Route 1. In previous years, Maine DIFW observed shorebirds using the entire shore of the project area, from Mill Cove south to the next minor cove, as indicated on Maine DEP maps. Maine DIFW noted that construction of the pier would result in displacement of feeding shorebirds during migration. Construction over water would be more disruptive to shorebirds than construction over land. To prevent unreasonable disturbance to shorebirds, Downeast proposed its draft Migratory Shorebird Adaptive Management Plan as part of its Shorebird Mitigation Plan, described further below. This plan indicates that Downeast would not construct its pier during the high use period of significant shorebird activity and describes how it would determine the period of high use. Exact time frames for work exclusion are as yet undetermined but would be based on baseline conditions.

Maine DIFW also expressed concerns regarding effects from operation of the proposed project in its letter dated April 2, 2007. Lighting and noise produced during normal terminal operations have the potential to make Mill Cove permanently unavailable as a viable feeding habitat to shorebirds. This possibility is exacerbated by both the length of time necessary to construct the terminal facilities, as well as the anthropogenic alteration to Mill Cove that effectively reduces the openness of habitat available for undisturbed feeding, and may elicit habitat avoidance responses by some shorebirds.

Discussions between Downeast and the Maine DIFW in the summer of 2007 and the Maine DIFW's testimony before the Maine Board of Environmental Protection (Maine BEP) in July 2007 at public hearings revealed that Downeast and Maine DIFW disagree about the area of significant wildlife habitats that are likely to be affected by operation of the proposed Project. During these discussions, Maine DIFW indicated that the presence of the LNG terminal, pier, and all associated operation activities could affect as much as 9.6 acres by operation of the proposed project. A number of published peer-reviewed articles on shorebird and other water birds and the effects of disturbance were reviewed by Downeast (Pfister et al. 1992; Rodgers and Smith 1997; Gill et al. 2001; West et al. 2002; Burger et al. 2004) to develop opinions on the effects of the construction and operation of the Downeast LNG import terminal on shorebirds. Downeast believes that the likely effects of the proposed LNG import terminal on shorebirds are less than expected by Maine DIFW because the pier is more than 1,000 feet from the primary feeding area. Given these distances from shorebird activity, pedestrian or vehicular traffic on the pier during operation of the project is unlikely to substantially affect feeding shorebirds. However, to mitigate for potential habitat loss of the Shorebird Area in Mill Cove, Downeast developed a Shorebird Mitigation Plan in consultation with the Maine DIFW. The revised Shorebird Mitigation Plan was finalized during a series of meetings in July 2007 between representatives from the Maine DIFW, Downeast, and Woodlot Alternatives, and accepted by the Maine DIFW on August 15, 2007. Appendix N contains the Shorebird Mitigation Plan submitted to the Maine DIFW as well as copies of agency communications. The Maine DIFW indicated that the proposed Shorebird Mitigation Plan reasonably mitigates for the shorebird impacts if Maine DEP determines that compensation for shorebird impacts is warranted. This agreement may be subject to modification during the Maine DEP permitting process.

The agreement includes provisions by Downeast to provide $3,000,000 in property acquisition funds to offset any potential impacts on shorebird habitat from the construction and operation of the Downeast LNG import terminal in Robbinston, Maine. The Maine DIFW may reduce the compensation amount if Downeast acquires conservation easements or purchases land in Mill Cove or other locations that result in permanent protection of a 250-foot riparian buffer. Additionally, this shorebird habitat compensation package includes research funding for an "advancing the science" program; a shorebird banding study; shorebird pre-construction, construction, and post-construction studies; and an adaptive management plan, as follows:

- Downeast would provide the Maine DIFW with $500,000 (included in the $3,000,000 described above) to establish an "advancing the science" program for shorebirds. Maine DIFW would develop and implement science programs that further an understanding for shorebird biology and enable better management of shorebird resources.

- In consultation with the Maine DIFW, Downeast would conduct a shorebird banding study for five years. The purpose of this study would be to further the understanding of shorebird biology and enable better management of shorebird resources. The program would be initiated within the calendar year that construction begins subject to the Maine BEP permit. Downeast would coordinate appropriate permits and scope of the study in conjunction with the Maine DIFW prior to initiation of the study.

- Downeast would develop and implement surveys to document shorebird use of Mill Cove to estimate potential effects of the LNG terminal construction and operation on shorebirds. Surveys would be designed in consultation with Maine DIFW. An annual report of study details, results, and recommendations would be prepared and distributed by Downeast to the Maine DIFW and to other state and federal natural resource agencies upon request.

- Downeast would develop an adaptive management plan in consultation with Maine DIFW for shorebirds that provides a process for identifying unreasonable adverse effects from development and operation of the LNG terminal and provides possible mitigation mechanisms. Adaptive management is intended to avoid, reduce, and minimize unreasonable adverse disturbances. The adaptive management plan is also found in Appendix N**.**

Additionally, Downeast has agreed to compensate for unavoidable impacts on coastal wetland areas, which include 0.1 acre of direct impact and an area overlain by the pier of 0.4 acre. The Maine DEP recommended compensation ratio for restoration of wetlands and significant wildlife habitats is 2 to 1. Downeast has identified two mitigation areas that are near one another; one is a coastal wetland with significant shorebird roosting, and the other is a salt marsh that transitions into a freshwater wetland, which also provides wildlife habitat. Downeast has been in discussions with the relevant agencies however a wetland mitigation package has not been finalized. We have recommended that Downeast continue to consult with the agencies and file the final wetland mitigation package with the Secretary (see section 4.4.1.2).

**Terrestrial Wildlife**

The land-based portion of the proposed terminal was historically used for agriculture and timber harvest, and as such is in various stages of forest succession. Spruce-fir forest dominates the proposed terminal site and provides the primary structural component for bird communities. This habitat is also heavily influenced by its proximity to Passamaquoddy Bay. Typical year-round residents include spruce grouse (*Dendragapus canadensis*), woodpeckers (*Picoides* spp.), and a variety of songbird species, such as dark-eyed junco (*Junco hyemalis*), black-capped chickadee (*Poecile atricapillus*), boreal chickadee (*Poecile hudsonicus*), and red-breasted nuthatch (*Sitta canadensis*). Small mammals that are expected to occur in the proposed terminal may include various rodent species (e.g., shrews, voles, moles, and squirrels), rabbits, and forest dwelling bats. The site of the terminal provides marginal habitat for medium and large terrestrial mammals due to its proximity to U.S. Route 1 and Passamaquoddy Bay. Downeast proposes to use off-site laydown yards, which are highly disturbed habitats that afford low-quality habitats to terrestrial wildlife.

A wetland/stream complex that flows through the northwestern portion of the proposed terminal site provides marginal habitat for potentially occurring salamanders, such as the northern dusky salamander (*Desmognathus fuscus*) and northern two-lined salamander (*Eurycea bislineata*). These two species require a highly oxygenated environment (Krohn et al. 2000; DeGraaf et al. 1992), which this stream is not likely to provide based on its morphology and low-gradient. Few reptile species are expected to occur in the proposed terminal due to its geographic location and absence of large open water sites. Species with potential to occur include common garter (*Thamnophis sirtalis)*, ringneck (*Diadophis punctatus*), and redbelly snakes (*Storeria occipitomaculata*); all may use the upland, particularly those locales with rich soil.

Shallow depressions created by skidders are a common artifact of timber harvest in the proposed terminal area. Though this habitat may function as a vernal pool, it would not be designated SVP status due to its anthropogenic origin, with the exception of those vernal pools that provide habitat to special status species. Species commonly associated with vernal pools, some of which are protected by the state of Maine and the FWS, such as wood frogs (*Rana sylvatica*), have been observed in this portion of the terminal area, and other vernal pool species such as spotted salamanders (*Ambystoma maculatum*) may also be present on-site.

We requested that Downeast conduct additional vernal pool surveys of the proposed LNG terminal during spring using vernal pool determination protocols that comply with the criteria outlined by Maine DEP, Chapter 335. In response to our request, Downeast completed vernal pool surveys in the terminal location during late April 2007. SVP habitat was not identified (Stantec Consulting 2007).

Constructing the terminal and off-site laydown yards would alter and reduce wildlife habitat in the predominantly spruce-fir forest through direct conversion of 47 acres to terminal facilities. Construction activities are also likely to cause mortality or injury to small, less mobile mammals that reside on-site. Spruce-fir habitat is not limited within Maine (see table 4.5.1.2-2). Of the 47 acres that would be converted, 9 acres would be wetlands. Impacts on wetlands and stream habitats may include sedimentation, vegetation removal, or channel modification. Adherence to Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* would minimize these effects. In addition, Downeast has attempted to use a design that impacts the least amount of land by implementing a compact facility design.

Short-term impacts, such as disturbance to wildlife outside of the boundary of the facility, would be expected only due to the noise and activity associated with construction. Operational noise would not significantly impact wildlife communities outside of the terminal site.

As with nocturnal species that use habitats adjacent to the offshore terminal facilities, birds that use habitats near the onshore terminal facilities could also be affected by night-lighting during operation of the terminal. Affected species could include barred owl (*Strix varia*), common nighthawk (*Chordeiles minor*), and whip-poor-will (*Caprimulgus vociferous*), all of which have been detected in the region (Sauer et al. 2005). The operational lighting would be limited to the extent necessary to maintain safe working conditions at the terminal. To mitigate impacts on nocturnal species, Downeast would strategically locate light fixtures to minimize light pollution beyond the terminal area.

#### 4.5.1.3 Sendout Pipeline

The following section discusses wildlife habitats that were identified within or adjacent to the proposed amended sendout pipeline and potential impacts on species using those habitats. These areas are depicted in figures M-3 through M-31 contained in Appendix M. Vegetation communities, including unique, sensitive, or protected plant communities are discussed in section 4.4 of this EIS.

**Wildlife-Habitat Associations**

The proposed amended sendout pipeline crosses mature upland forest types (i.e., spruce-northern hardwoods and white-pine-mixed hardwoods), upland early successional forests (i.e., aspen-birch woodland/forest complex), upland maintained openings, and wetlands. Wetland types are discussed in section 4.4.1 of this EIS. Old-growth forest is not present within areas crossed by the proposed sendout pipeline.

Continuous mature forest interspersed with young forest is the principle character of the landscape along the proposed sendout pipeline route. Field surveys documented the presence of several forest dwelling species, such as snowshoe hare (*Lepus americanus*), porcupine (*Erethizon dorsatum*), and fisher (*Martes pennanti*). Forest communities support diverse assemblages of mammals due to the special structural features that are present, such as cavity trees for denning, seedling-sapling trees for food, and woody debris for cover. Small mammals, such as mice, voles, and shrews, need forests with closed canopy, thick litter, and woody debris to meet requirements throughout their lifetime. Other small mammals such as smoky shrew (*Sorex fumeus*) and northern flying squirrel (*Glaucomys sabrinus*) are found in upland forests crossed by the proposed sendout pipeline. Furbearing mammals such as bobcat (*Felis rufus*), and long-tailed weasel (*Mustela frenata*) would also be likely to occur in upland forests.

Mature forests tend to have a high incidence of dead and dying standing trees, which are important elements of habitat diversity in forests. Standing snags and cavity trees provide nest sites; foraging substrate; plucking posts for raptors; singing, hammering, or drumming sites; food caches or granaries; courtship display sites; roosting sites; and hunting and hawking perches. The contiguously forested landscape provides secure and expansive habitat for forest raptors, such as broad-winged hawk (*Buteo platypterus*) and Cooper's hawk (*Accipiter cooperii*). Forest raptors use the forest openings to hunt rodents and smaller birds. Habitat for forest raptors can be found at numerous locations along the proposed sendout pipeline in the form of mature forest interspersed with younger stands.

Because spruce-fir forests are intensively managed for timber production, there is an abundance of food available for both black bear (*Ursus americanus*) and moose (*Alces alces*). Young, regenerating stands provide high-quality browse and cover for moose, and early successional forests produce thick crops of naturally occurring fruits and berries that are important foods of juvenile and adult bears. The prevalence of wetland communities throughout the region is attractive and important for both species, particularly during the spring when moose and bear nutritional demands are high, and they look to forage on new plant growth in thawing wetlands.

Black bear and moose scat were observed in several locations along the sendout pipeline route; however, neither species is abundant in Washington County.

Many forest birds require, or at least use, early-successional forests. Many shrub-nesting birds require young forest openings larger than one acre. Larger forest openings provide an interior of dense vegetative cover away from edges where mammalian predators may travel. Early-successional birds include several migrant songbirds, such as mourning warbler (*Oporornis philadelphia*), white-throated sparrow (*Zonotrichia albicollis*), and Nashville warbler (*Vermivora ruficapilla*). The red-tailed hawk (*Buteo jamaicensis*) would likely occur in open areas and early successional woods that have scattered high perches.

American woodcock (*Scolopax minor*) and ruffed grouse (*Bonasa umbellus*) are fairly common in early successional forests, and were observed during field surveys. Woodcock are migrant birds that breed in the region. Woodcocks perform courtship displays in open habitats as small as one acre. Daytime foraging habitats are found in dense cover of alder, aspen or birch that also have damp soils with abundant earthworms. Wild turkeys (*Meleagris gallopavo*) and their habitat also occur along the proposed sendout pipeline. The red-tailed hawk would occur in similar habitats with scattered high perches. Other birds such as black-billed cuckoo (*Coccyzus erythropthalmus*), whip-poor-will, flycatchers (*Empidonax* spp.), waxwings (*Bombycilla* spp.), and dark-eyed junco are also expected to occur in early successional forest habitats crossed by the proposed sendout pipeline.

Streams, ponds, and wetlands occur along portions of the sendout pipeline right-of-way. Open water and wetlands attract mammals such as beaver (*Castor canadensis*), muskrat (*Ondatra zibethicus*), raccoon (*Procyon lotor*), moose, and bats, as well as birds such as loons (*Gavia* spp.), grebes (*Podilymbus* and *Podiceps*), ducks (*Anas* spp.), osprey (*Pandion haliaetus*), common yellowthroat (*Geothlypis trichas*), yellow warbler (*Dendroica petechia*), and belted kingfisher (*Ceryle alcyon*). Amphibians and reptiles such as eastern newt (*Notophthalmus viridenscens*), bullfrog (*R. catesbeiana*), snapping turtle (*Chelydra serpentine*), and northern watersnake (*Nerodia sipedon*) also use these habitats for breeding and feeding. All community types except spruce-fir forest are expected to support waterbirds during some phase of the annual life cycle according to Krohn et al. (2000) and DeGraaf et al. (1992).

Several species potentially occurring along the proposed sendout pipeline exist within a fairly specific environmental niche, such as the American bittern, (*Botaurus lentiginosus*), least bittern (*Ixobrychus exilis*), Virginia rail (*Rallus limicola*), and sora (*Porzana carolina*). These four species all require the presence of some emergent vegetation on their breeding grounds and are secretive in nature, often well camouflaged and hidden amongst the vegetation. The least bittern possesses perhaps the most constrained set of habitat components of these species: flooded robust vegetation (most often cattail), stable water levels, and large expanses of open water (Moore 2000; Gibbs and Melvin 1990; Weller 1961). Of these four webless waterbirds, the least bittern was listed as endangered (Maine DIFW 2007a) and is the most habitat-limited in the region. Based on known occurrences of least bittern (Maine DIFW 2007a), it is unlikely to occur within the proposed sendout pipeline right-of-way.

Six bat species, including the little brown and northern long-eared myotis (*Myotis lucifugus* and *M. septentrionalis*), silver-haired bat (*Lasionycteris noctivagans*), eastern pipistrelle (*Pipistrellus subflavus*), hoary and red bats (*Lasiurus cinereus* and *L. borealis*), and big brown bat (*Eptesicus* *fuscus*), have the potential to occur in habitats associated with the sendout pipeline right-of-way. Suitable bat habitat would be limited to forests, forest openings, and open water. Cave environments have not been located in the vicinity of the sendout pipeline, and none are expected to be discovered in the region. However, any forest-dwelling bats would find suitable roosting habitat in trees with peeling bark or on the ground in the forest litter. Additionally, foraging habitat is available along the gravel roads, open stream corridors, and over ponds and impoundments. Habitat for forest-dwelling bats is prevalent in the Downeast LNG Project area.

Species warranting particular management attention include the blue-spotted salamander (*Ambystoma laterale*), which is likely to occur in hardwood forest types associated with the proposed sendout pipeline, providing that adequate breeding pools are present. The northern leopard frog (*Rana pipiens*) is associated with slow moving streams/pond-like environments, hardwood-dominated uplands, and most notably, wet meadows and fields for breeding. These two amphibians are listed in Maine as species of special concern.

### Impacts on Wildlife Species

Wildlife habitat may be lost or transitioned into a different habitat type, such as the transition of forested land into scrub-shrub and graminoid vegetated communities. Forest fragmentation would occur along the right-of-way, which could degrade wildlife habitat for interior woodland species sensitive to edge effects, and increase predation on some species in proximity to the right-of-way. Downeast has collocated the pipeline, to the extent practical, along existing rights-of-way, thereby minimizing additional forest fragmentation. In all, the sendout pipeline will temporarily impact 226.7 acres, and permanently impact 122.5 acres of wildlife habitats, as listed in table 4.5.1.3-1.

TABLE 4.5.1.3-1

**Acres of Impact on Terrestrial Wildlife Habitats by Construction and Operation of the Sendout Pipeline**

| Facility | Forest Land | | Wetlands | | Agricultural | | Grassland | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Con. | Op. | Con. | Op. | Con. | Op. | Con. | Op. | Con. | Op. |
| 30-inch-diameter Sendout Pipeline a/ | 151.0 | 98.9 | 26.6 | 14.2 | 2.0 | 1.1 | 11.7 | 7.4 | 191.3 | 121.6 |
| Off-site pipe laydown and storage areas | 15.7 | 0 | 1.9 | 0 | 0.7 | 0 | 0 | 0 | 18.3 | 0.0 |
| Valve Station (MP 17.17) | 0.3 | 0.4 | 0 | 0 | 0 | 0 | 0 | 0 | 0.3 | 0.4 |
| Pigging Receiving and Gas Metering Facility at Baileyville Terminus b/ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ATWS and HDD ATWS | 12.6 | 0 | 0.9 | 0 | 1.7 | 0 | 1.0 | 0 | 16.2 | 0 |
| Access Roads c/ | 0.5 | 0.5 | 0.1 | 0 | 0 | 0 | 0 | 0 | 0.6 | 0.5 |
| **Total Sendout Pipeline** | **180.1** | **99.8** | **29.6** | **14.2** | **4.4** | **1.1** | **12.7** | **7.4** | **226.7** | **122.5** |

a/ Includes nominal 25-foot-wide construction right-of-way and a 50-foot-wide operation right-of-way.
b/ Pigging facilities at the Baileyville Compressor Station would be constructed in previously disturbed areas within the station property.
c/ Only the access road at MP 15.4 will require clearing for a new road base. The other three temporary access roads have existing road bases; however, they will need to be upgraded prior to construction of the sendout pipeline and will not be restored to pre-existing conditions.

Part of the amended sendout pipeline route would entail a 6,621-foot-long HDD under the St. Croix River from MP 14.1 to MP 15.3. Based on desktop review of information, Downeast determined that there are no known rare botanical or wildlife features or habitat within the construction area along the St. Croix River corridor. Nonetheless, it would conduct surveys to identify any sensitive areas prior to the start of construction. The FWS requested information about the potential impact of the HDD of Magurrewock Marsh on nesting bald eagle habitat. Downeast has indicated that the HDD drilling location is more than 0.5 mile from the location of the bald eagle nest at the Magurrewock Marsh. The drilling activity and associated equipment and materials storage would be outside the noise and staging buffer areas established by the FWS. Downeast would adhere to its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* to protect water quality and wildlife during construction and operation of the sendout pipeline. Downeast would restore those affected areas and reseed using seed mixtures of plant species native to the area.

<u>Mammals</u>

Short-term direct effects to terrestrial mammals would occur during construction of the sendout pipeline in the form of increased noise and human presence, which could displace some individuals. Forested habitat alteration would have short-term and long-term effects in the form of temporary (151 acres) and permanent (98.9 acres) conversion of mature forest to early successional forest and maintained openings (see table 4.5.1.3-1). Construction activities are likely to cause mortality or injury to small, less mobile mammals that reside on-site. During construction, mobile species would be displaced, and some would return after construction is completed, particularly those species that use forest edges. Some mammals may benefit from a permanent corridor of herbaceous vegetation, such as bats and white-tailed deer (*Odocoileus viginianus*), both of which would use the right-of-way for foraging and as a dispersal corridor that provides linkages between sources and sink populations throughout the landscape.

<u>Birds</u>

Construction and operation of the sendout pipeline would directly affect terrestrial birds by converting upland and wetland forest to permanent, linear forest openings. Changes in vegetation and forest structure are discussed in section 4.4.2 of this EIS. The greatest loss of habitat would occur in forest areas, totaling 151 acres of temporary and 98.9 acres of permanent disturbance, followed by disturbance to wetland habitats that would total 26.6 acres during construction and 14.2 acres during operation (see table 4.5.1.3-1).

The creation of a linear deforested corridor may also have indirect effects to birds. Pipeline corridors create brushy edges that are attractive to many shrub-nesting birds, such as northern cardinal (*Cardinalis cardinalis*) and common yellowthroat. Pipeline corridors in heavily forested landscapes have been reported to attract birds dependent on open habitats, such as has been the case for wild turkeys along parts of the M&NE corridor (Maine DIFW 2006b). Simultaneously, the right-of-way may also attract mammalian nest predators, such as striped skunk (*Mephitis mephitis*) and raccoon. However, negative edge effects may not be significant in such a heavily forested landscape. Additionally, the sendout pipeline has been sited along existing linear corridors for powerlines, roadways, all-terrain vehicle (ATV) and snowmobile trails, and in areas of timber harvesting. Because this low-level fragmentation already exists in the landscape, we conclude the proposed sendout pipeline corridor would have minimal contribution to the effects associated with mature forest conversion and associated edges.

Mitigation of waterbird impacts would rely on strict adherence to BMPs for erosion control and maintenance of riparian buffers. Heavy equipment would be supported on weight-bearing surfaces (e.g., crane mats) to avoid creating micro-topographic changes in wetland habitats. Downeast has stated that it would prohibit pipeline construction in significant waterfowl and wading bird habitat during the breeding season from April 15 to July 15. Therefore, because of Downeast's proposed mitigation, we conclude impacts on birds (including wading, waterfowl, and migratory birds) would not be significant.

Reptiles and Amphibians

Construction and operation of the sendout pipeline has the potential to affect both the quantity and quality of habitat available to reptiles and amphibians. During construction, mobile species would be displaced to adjacent areas, whereas less mobile species might be injured or killed. These species are found in most habitats crossed by the sendout pipeline, which would affect 226.7 acres during construction and 122.5 acres during operation. These impacts include 29.6 acres of temporary and 14.2 acres of permanent impacts on wetland habitats (see table 4.5.1.3-1). Where wetlands and streams must be traversed, impacts associated with construction activities could include short-term sedimentation (from erosion) and topographic changes (from heavy machinery) to the system. Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* outline measures that minimize impacts on resources. Construction and operation of the proposed sendout pipeline is not expected to adversely affect reptile and amphibian populations.

**Moosehorn National Wildlife Refuge**

The Moosehorn NWR is principally managed to protect wildlife, including migrating waterfowl, wading birds, shorebirds, upland game birds, songbirds, and birds of prey. A species that receives much attention and research at the Moosehorn NWR is the American woodcock. Woodcock are known to use early successional habitats (clearings, alder thickets, young hardwood forests) for courtship rituals and breeding. Originally, the sendout pipeline crossed 3.5 miles of the Moosehorn NWR; however, on September 27, 2007, the FWS deemed the proposed pipeline route to be inappropriate in the NWR. The amended sendout pipeline would no longer cross the Moosehorn NWR. At its closest point, the amended pipeline route would be more than 0.25 mile away from the Moosehorn NWR between MP 10.0 and MP 10.5, MP 12.3 and MP 14.3, MP 15.1 and MP 15.2, and between MP 17.3 and MP 17.8, for a total of about 3.1 miles. In a comment letter on the draft EIS, the FWS has expressed concern about the impacts from the sendout pipeline construction activities along the boundaries of the Moosehorn NWR and the timing of construction near the Moosehorn NWR. While we believe that Downeast has addressed the FWS's concern by moving the proposed pipeline outside of the NWR, continued consultation with the FWS regarding construction near the refuge is appropriate. Therefore, **we recommend that:**

- **Downeast shall continue to consult with the FWS to determine if there are FWS-recommended seasonal or construction timing restrictions that Downeast could incorporate into its construction plan to minimize impacts of the sendout pipeline**

**along the Moosehorn NWR boundaries. <u>Prior to construction of the pipeline facilities</u>, Downeast shall file with the Secretary copies of its correspondence with FWS and a description of the construction timing restrictions and/or mitigation measures it has agreed to implement along the Moosehorn NWR boundaries.**

**Significant Wildlife Habitats**

Significant and essential wildlife habitats in Maine are regulated under NRPA, which is administered by the Maine DEP. Significant wildlife habitats including vernal pools and IWWH were identified along the proposed sendout pipeline during correspondence with Maine DIFW, Maine NAP, and FWS. Additionally, one deer wintering area is crossed twice by the sendout pipeline.

Due to the amount of significant wildlife habitat that would be disturbed by the proposed project, the Maine DEP requested compensation from Downeast. Downeast developed, in consultation with the Maine DEP, Maine DIFW, FWS, COE and EPA, several mitigation alternatives that specifically focus on preserving inland wetlands that contain significant wildlife habitat. Downeast will need to continue its consultation with these agencies for approval of a final, comprehensive wetland mitigation plan that addresses coastal and freshwater wetlands, areas used by tidal and inland wading waterfowl, and SVPs.

<u>Significant Vernal Pools</u>

Maine DEP and legislature adopted rules governing, among others, SVP habitats, which were implemented on September 1, 2007. A vernal pool, defined by NRPA, is a natural, temporary to semi-permanent body of water occurring in a shallow depression that typically fills during the spring or fall and may dry during the summer; it has no permanent inlet, and lacks viable populations of predatory fish. Downeast conducted surveys along the proposed sendout pipeline in May and again in October 2007 to determine the locations of SVP habitats. See section 4.4.1.3 for a detailed discussion of vernal pools along the sendout pipeline.

<u>Inland Waterfowl and Wading Bird Habitat</u>

Waterfowl habitat can be grouped into three broad categories: breeding; migration and staging; and wintering habitats. Wading bird habitat consists of breeding, feeding, roosting, loafing and migration stopover areas. Waterfowl and wading bird habitats are ranked as high, moderate, or low value based on observed species use, dominant wetland type, and the diversity, size and interspersion of wetland types; moderate and high value IWWH are protected in Maine. A high to moderate value IWWH is a complex of freshwater wetland and open water areas, and includes a 250-foot wide zone surrounding the wetland complex. The 250-foot buffer zone may include upland areas outside of the wetland.

Nine discrete areas of IWWH occur along the amended sendout pipeline route. Many waterfowl and wading bird habitats crossed by the sendout pipeline are considered moderate to high value IWWH (see sendout pipeline figures in appendix M). Through refinements of its amended sendout pipeline route, Downeast has further reduced its impact on six areas of IWWH, affecting a total of 4.78 acres during construction and operation of the sendout pipeline (table 4.5.1.3-2). Possible effects to these bird habitats as well as vernal pools include increased turbidity and associated suspended solids, which could cause indirect effects such as shifts in prey community composition when nutrient enrichment and light attenuation alters primary productivity, or decreased ability to detect and capture prey. Heavy equipment could cause rutting and slight changes in elevation that could affect hydrology characteristics of IWWHs and vernal pools. Discharge of pollutants from worksite machinery into nearby aquatic habitats could occur. Noise resulting from construction activities could disturb breeding or migrating individuals (e.g., nest failure, reduced recruitment to breeding populations).

TABLE 4.5.1.3-2

**Inland Waterfowl and Wading Bird Habitat Impacts Along the Sendout Pipeline**

| Milepost | Temporary Impacts (Acres) | Permanent Impacts (Acres) | Total |
|---|---|---|---|
| 4.1 a/ | 0.0 | 0.0 | 0.0 |
| 7.7 | 0.4 | 0.7 | 1.1 |
| 8.5 a/ | 0.0 | 0.0 | 0.0 |
| 13.0 | 0.3 | 0.4 | 0.7 |
| 14.0 | 1.0 | 1.5 | 2.5 |
| 14.2 a/ | 0.0 | 0.0 | 0.0 |
| 17.6 b/ | 0.3 | 0.1 | 0.4 |
| 25.1 a/ | 0.0 | 0.0 | 0.0 |
| 28.9 | 0.02 | 0.06 | 0.08 |
| **Total** | **2.02** | **2.76** | **4.78** |

a/ Denotes IWWH avoidance through HDD.
b/ Impacts on IWWH minimized through use of HDD in much of this wetland.

Construction activity is a disturbance that represents a potential impact on migrating, nesting, and brooding waterbirds. Mitigation of noise disturbance would be accomplished by limiting construction in sensitive areas to the non-breeding season for species whose preferred community types within IWWH exist in or adjacent to the construction activity area. Downeast would mitigate for impacts on IWWH and adjacent buffer zones by avoiding construction activities in those areas from April 15 to July 15. Furthermore, Downeast would implement its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* during construction of the proposed sendout pipeline. Downeast would preserve wetland topography by limiting heavy equipment use to seasonal and edaphic conditions that are capable of supporting construction machinery. This would include operating during frozen ground conditions or on adequate weight-bearing substrates, either placed or natural. Downeast would minimize the risk of pollution by keeping fuels, lubricants, and other potential construction or machinery associated pollutants at least 100 feet from aquatic resources, except under limited, highly controlled circumstances. Given that Downeast would avoid construction during sensitive breeding periods for waterfowl and wading birds, and used in combination with Downeast's adherence to protective measures in its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*, significant impacts on IWWH from construction and operation of the proposed project are not anticipated.

To mitigate for the unavoidable impacts on wetlands and significant wildlife habitat associated with the proposed sendout pipeline, as well as other portions of the Project, Downeast proposed wetland/upland preservation at three off-site areas as part of its compensation plan for wetlands and IWWH. One site does not contain wetlands or waters of the United States (as determined from NWI mapping), but instead provides a buffer to wetland complexes to the north and east of the parcel. Another site contains upland forest habitat, 23.2 acres of wetlands (23.1 acres of PFO and 0.6 acres of PEM/PSS wetlands), and a tributary to Beaver Lake, which is within a resource protection zone. Downeast would purchase the property and place the land in conservation to be protected from residential and commercial development in perpetuity.

The compensation for freshwater wetlands includes preservation of 157 acres of wetlands and surrounding upland buffers. Of these 157 acres, 35 acres consist of IWWH. For preservation, Downeast would purchase the property and place the land in conservation to be protected from residential and commercial development in perpetuity. Downeast is currently discussing the potential for putting the preserved parcels under the stewardship of a regional land trust.

As indicated in section 4.5.1.2, discussion with the relevant agencies is ongoing, and we have recommended that Downeast finalize the wetland mitigation package prior to the construction of the pipeline or LNG terminal facilities (see section 4.4.1.2).

<u>Deer Wintering Areas (DWA)</u>

Forest stands of mature conifers with tree height greater than 30 feet and crown closure of greater than 60 percent provide critical winter habitat for deer. Wintering habitat is limited in availability, comprising only 2 to 25 percent of the land base in various parts of the state (Maine DIFW 2007b). More specifically, DWA is defined as, "forested areas used by deer when snow gets more than 12 inches deep in the open and in hardwood stands, when the depth that deer sink into the snow exceeds 8 inches in the open and in hardwood stands, and when mean daily temperature is below 32 degrees" (Maine DIFW 2007c). The sendout pipeline crosses one DWA twice between MP 16.72 and MP 16.80, and again from MP 16.86 to MP 17.02, affecting as much as 2.19 acres. During construction of the sendout pipeline, this DWA would not be available to overwintering deer, representing a loss of cover and forage. While much of the affected right-of-way would be allowed to revegetate over time, a portion of the right-of-way would be subject to routine vegetation clearing and represents a permanent loss of DWA habitat. To minimize potential impacts during construction of the proposed sendout pipeline, Downeast would implement its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*. In addition, Downeast has agreed to consult with Maine DIFW and Maine DEP to develop DWA mitigation measures similar to those proposed by M&NE during its previous construction of its pipeline. Therefore, **we recommend that:**

- **Downeast should continue to consult with the Maine DEP, DIFW, and BEP to finalize its DWA mitigation package. <u>Prior to construction of the pipeline facilities</u>, Downeast should file with the Secretary the final DWA mitigation package and copies of the consulted agencies' comments on the final package and applicable approvals.**

### 4.5.2 Aquatic Resources

#### 4.5.2.1 Waterway for LNG Marine Traffic

The aquatic habitats associated with the LNG marine traffic route are open waters underlain by a gently rolling seabed with a drowned shoreline (OMG 2005). The marine waters traversed by LNG vessels in route to the proposed terminal provide habitat to a number of marine species, which are discussed in this section. Head Harbour Passage and the associated waters of Cobscook Bay are considered the most species-rich area in the western North Atlantic (Larsen 2004). Federally listed threatened and endangered species known to occur in these waters are discussed in section 4.6 of this EIS.

**Marine Mammals**

Several species of marine mammals, including whales, porpoises, dolphins, seals, and other pinnipeds have the potential to occur along the proposed LNG marine traffic route, and are listed in table 4.5.2.1-1. Life history and published accounts of population distribution were reviewed to determine species that have a high likelihood to be affected by the proposed Downeast LNG Project. This review resulted in the identification of five species that are common within the limit of the territorial seas that would be transited by LNG vessels, including gray seal, harbor seal, harbor porpoise, white-sided dolphin, and minke whale. These species are discussed in further detail below. Other species that are less likely to be encountered within the proposed project area, but may occur as transient individuals, include Atlantic spotted dolphin, beaked whales, beluga whales, bottlenose dolphin, common dolphin, white-beaked dolphin, harp seal, hooded seal, killer whale, long-finned pilot whale, northern bottlenose whale and short-finned pilot whale. Threatened and endangered marine mammals are discussed in section 4.6 of this EIS and in our BA included as Appendix C.

In general, marine mammal occurrence along the proposed waterway increases from spring and summer and decreases from fall to winter. Their occurrence is usually related to the distribution of each species' preferred prey (e.g., copepods and krill for baleen whales, fish prey for toothed whales).

Resident colonies of gray seals occur in coastal Maine; pupping occurs on several isolated islands along the Maine coast (Waring et al. 2011). Maine is also a winter breeding ground for gray seals.

Harbor seals are the most abundant pinniped species found in western North Atlantic waters, and are found in all nearshore waters of this region. Important habitat for seals occurs along the transit route and the adjacent coastline, and suitable seal habitat includes Passamaquoddy Bay. Seal habitats include feeding and breeding areas, and pupping and haul-out ledges. An estimated 30,000 harbor seals spend all or part of the year in the Gulf of Maine, including small islands along the Maine coast (GoMOOS 2007). Seals haul out on remote exposed rocks, sandbars, rocky shores, and ice, but are usually solitary in the water. They are not migratory, but instead make seasonal movements in response to prey distribution. From September to late May, seasonal seal movements occur southward from the Bay of Fundy to the coasts of southern New England (Waring et al. 2011). Pupping season occurs in mid-May through June, and takes place primarily along coastal Maine (see Appendix F, figures F-20 and F-22). Harbor porpoises prefer nearshore habitats, especially waters less than 490 feet (50 meters) deep. Dense populations of this species occur in the Gulf of Maine and the southern Bay of Fundy. Harbor porpoises are considered year-round inhabitants in the Gulf of Maine.

TABLE 4.5.2.1-1

**Marine Mammals Expected to Occur Along the LNG Marine Traffic Route and LNG Terminal a/**

| Species | Marine Preference | Project Area | Occurrence | Timing of Occurrence |
|---|---|---|---|---|
| Atlantic Spotted Dolphin *(Stenella frontalis)* | continental shelf waters; inshore | waterway for LNG marine traffic | Incidental | - |
| Beaked Whales (*Mesoplodon spp.)* | continental shelf waters; inshore | waterway for LNG marine traffic | Incidental | late spring, summer |
| Beluga (*Delphinapterus leucas*) | inshore waters, estuarines, bays | waterway for LNG marine traffic | Incidental | - |
| Bottlenose Dolphin (*Tursiops truncates*) | offshore and inshore (two different populations) | waterway for LNG marine traffic | Occasional | - |
| Common Dolphin (*Delphinus delphis*) | outer continental shelf | waterway for LNG marine traffic | Occasional | mid-summer to autumn |
| Cuvier's Beaked Whale (*Ziphius cavirostris)* | continental shelf edge; deep water | waterway for LNG marine traffic | Incidental | late spring, summer |
| Grey Seal (*Halichoerus grypus*) | coastal waters | waterway for LNG marine traffic<br>LNG Terminal | Common | year-round |
| Harbor Porpoise (*Phocoena phocoena*) | coastal waters less than 150 meters deep | waterway for LNG marine traffic<br>LNG Terminal | Common | year-round; most abundant in summer |
| Harbor Seal (*Phoca vitulina*) | coastal waters | waterway for LNG marine traffic | Common | year-round |
| Harp Seal (*Pagophilus groenlandicus*) | coastal waters; inshore waters | waterway for LNG marine traffic | Occasional; increasing | late spring, summer |
| Hooded Seal (*Cystophora cristata*) | offshore waters; continental shelf waters during winter | waterway for LNG marine traffic | Occasional; increasing | late spring, summer |
| Killer Whale (*Orcinus orca*) | continental shelf less than 200 meters deep | waterway for LNG marine traffic | Incidental | - |
| Long-finned Pilot Whale (*Globicephala melas*) | continental shelf; offshore (winter) | waterway for LNG marine traffic | Incidental | late spring through autumn |
| Minke Whale (*Balaenopterus acutorostrata*) | continental shelf; coastal | waterway for LNG marine traffic | Common | spring and summer (period of greatest abundance); rarely seen in winter |
| Northern Bottlenose Whale (*Hyperoodon ampullatus)* | deep waters off the Scotian Shelf | waterway for LNG marine traffic | Incidental | - |
| Short-finned Pilot Whale (*G. macrorhynchus*) | continental shelf and slope waters; likely south of New Jersey | waterway for LNG marine traffic | Incidental | - |
| White-beaked Dolphin (*Lagenorhynchus albirostris)* | Shallow, temperate to subpolar waters | waterway for LNG marine traffic | Occasional | most abundant in July, August, and September |
| White-sided Dolphin (*Lagenorhynchus acutus*) | continental shelf and slope waters with seasonal inshore / offshore movements | waterway for LNG marine traffic | Common | summer |

a/ Marine mammals protected by the ESA are discussed in section 4.6 of this EIS.

White-sided dolphins are especially abundant in the Gulf of Maine; from July to September, they are frequently found in waters ranging from the southern Gulf of Maine out along the continental shelf and slope to Cabot Strait. They likely make inshore/offshore seasonal movements in response to changing prey distribution. White-sided dolphins are generally observed in large pods of greater than 100 individuals.

Minke whales are found in the continental shelf or coastal waters of the North Atlantic Ocean, especially within the Gulf of Maine and the Bay of Fundy. They are common and widely distributed, and most abundant in spring and summer.

**Sea Turtles**

One species of sea turtle, the leatherback sea turtle (*Dermchelys coriacea*) is known to occur in the waters of Passamaquoddy Bay and the Bay of Fundy during the summer and fall (typically June through October). This species is currently listed as endangered by both the United States and Canada. Information regarding this species including potential impacts and proposed mitigation measures associated with the project are discussed in section 4.6 of this EIS.

**Finfish and Invertebrates**

Numerous pelagic and demersal finfish species (including those of commercial and recreational importance) are known to occur within the waters associated with the LNG transit route. Many of these species are also known to occur in the waters associated with the LNG terminal and are discussed in detail in section 4.5.2.2 of this EIS. A comprehensive EFH assessment is provided in Appendix G and summarized in section 4.5.3.

Aquaculture also occurs in the vicinity of the transit route. There are 8 aquaculture sites located in the U.S. waters along the transit route and 15 aquaculture sites located in the Canadian waters along the transit route.

The most common and commercially important shellfish found within the waters associated with the transit route are the soft-shell clam (*Mya arenaria*), blue mussel (*Mytilus edulisi*), and the northern sea scallop (*Placopecten megellanicus*). In Maine waters, the soft-shell clam is primarily an intertidal benthic, infaunal clam that lives in a variety of sediments from coarse sand to soft silt at a depth in the sediment of only a few millimeters. The blue mussel is an epibenthic species that attaches itself to the bottom substrate through secreted fibers called byssal threads or byssus. They can be found both intertidally and subtidally in Maine waters on sediments ranging from coarse gravel and relic shell to fine silt where they often form large mats or beds just above and extending below the low watermark. The northern sea scallop is a strictly subtidal species that is found on bottoms ranging from coarse gravel and cobble to fine silt, although firmer bottom subject to swift currents is preferred.

Harvesting of the soft-shell clam can only be accomplished using hand implements (i.e., clam rakes). Blue mussels and scallops may also be harvested by hand; however, they are usually harvested commercially using dredges. All three species are harvested in the region associated with the project, but sea scallops are by far the most commercially important of the three. According to Russell Write of the Maine DMR Marine Patrol for the Eastport-Lubec area, the shorelines along most of the transit route in Western Passage and Friar Roads are steep and rocky offering little habitat for soft-shell clams or mussels. In addition, the majority of the habitat that does exist is closed to harvesting due to pollution. Currently, only Lewis Cove, the southern portion of Mill Cove, and portions of the coastline along the Passamaquoddy reservation are open to shellfish harvesting. Several sections of the waterway from Todd Head (Eastport) to Frost Point (Perry) are closed. Shellfish harvesting in Gleason Cove is restricted, requiring a permit from the Maine DMR. Sea scallops, on the other hand, are harvested to some extent throughout the area; however, harvesting is concentrated principally in Cobscook Bay and South Bay just south and west of the transit route. Based upon a 1977 Maine DMR coast-wide survey, the only molluscan habitat near the LNG transit route is soft-shell clam habitat.

Lobstering is also a significant commercial fishery within the state of Maine, accounting for nearly 75 percent of the value of Maine's marine resources. Maine lobster fishing occurs year-round, with effort concentrated close to shore during summer months, shifting to higher concentration in offshore waters during winter. Commercial lobster fishing is known to occur along the majority of the proposed transit routes. Within the proposed eastern transit route following the VTS, lobster fishing is highly seasonal for the Grand Manan lobster fishery, taking place from the second Tuesday in November to January 15, as well as between April 15 and June 30. Within the proposed Grand Manan Channel route, the lobster season extends from June 1 through November 30. In addition, according to sworn testimony provided to the Maine BEP, the waters of Western Passage and Passamaquoddy Bay extending along the Perry, Maine shoreline from Gleason Cove to points north of the proposed project site in Mill Cove out to Canadian waters are also heavily fished for lobsters between the months of April and December. In federal waters, the American lobster fishery is managed by NOAA Fisheries Service, state, federal and Constituent Programs Office, under the Atlantic Coastal Fisheries Cooperative Management Act and under the Atlantic States Marine Fisheries Commission Interstate Fishery Management Plan in state waters (NOAA Fisheries 2008a). Federal lobster permit holders who intend to fish for lobster with trap gear during the fishing year are required to designate lobster management areas and tag all lobster traps. Federal lobster regulations require federal permit holders to abide by the most restrictive of either state or federal trap limits. In the state of Maine, the Maine DMR regulates trap limits and issues trap tags.

Commercial harvesting of marine worms including sandworms (*Nereis virens*) and bloodworms (*Glycera dibranchiate*) also occurs along the transit route. Both sandworms and bloodworms use intertidal mudflats and prefer areas dominated by fine sandy and silty soil with high organic contents (Wilson and Ruff 1988). While both bloodworms and sandworms are largely subterranean, the species emerge from the substrate and enter the water column to spawn and feed. Both species spawn in May and June, where spawning and then larval development occurs on the sediment surface. Harvesting of bloodworms and sandworms is currently regulated by the Maine DMR and represents an important commercial industry to many coastal communities. These species are also an important food source for a number of marine species. According to the Maine DMR, four commercial worm harvesting areas occur along the transit route, including Gleason Cove, Halfmoon Cove, Carlow Island Causeway, and Carrying Place Cove.

**Zooplankton and Ichthyoplankton**

Invertebrate zooplankton and the planktonic eggs and larvae of many fish species (ichthyoplankton) make up an important portion of the plankton community within the waters of the LNG transit route. Many of the planktonic species are also known to occur in the waters associated with the LNG terminal. These species are discussed in detail in section 4.5.2.2 of this EIS.

**Special Interest Areas**

Downeast proposes to use two LNG transit routes near Grand Manan Island, including the Grand Manan Channel to the west of the island or a channel to the east of the island (a designated vessel traffic zone generally used by all vessels traveling up through the Bay of Fundy) (see Appendix F, figures F-1 to F-10). Neither transit route option in this area would cross any U.S. marine sanctuaries or marine protected areas of interest; however, the route east of Grand Manan would cross a small portion of the Canadian Division of Fisheries and Oceans' Grand Manan Basin Whale Sanctuary. Right whales are known to frequent this sanctuary as well as the surrounding waters of the Bay of Fundy during the summer and fall. At present, vessels typically do not traverse the sanctuary if right whales are known to be in the area. In addition, NOAA has introduced mitigations to reduce ship strike of right whales which includes reducing vessel speed to 10 knots when traversing seasonal management areas or dynamic management areas established due to high concentrations of right whales (50 CFR Part 224). These measures apply to all vessels 65 feet or longer.

**Potential Impacts of LNG Marine Traffic**

Marine Mammals and Sea Turtles

At least 22 species of marine mammal and one species of sea turtle are likely to occur in the waterway for LNG marine traffic. Whale habitats include feeding and breeding grounds, as well as migration routes in the open ocean and Head Harbour Passage. Important habitat for seals occurs along the transit route and the adjacent coastline and in Passamaquoddy Bay. Seal habitats include feeding and breeding areas and pupping and haul-out ledges. Dolphin and porpoise species may also occur in the Bay of Fundy and Passamaquoddy Bay for feeding.

Potential impacts on marine mammals that use waters in or near the proposed LNG marine traffic route may include vessel collisions, acoustic harassment (e.g., masking of communication/ echolocation), physical harassment, and exposure to pollutants and marine debris. In reviewing stock assessment reports, it appears that whales are more likely to suffer injury or mortality from vessel collisions, whereas seals, porpoises and sea turtles are more likely to become entangled in fishing gear. Vulnerability to vessel collisions may result from the whale's limited ability to detect or maneuver around on-coming vessels, or because the species is at the surface feeding, resting, mating, and/or nursing. Impacts and mitigations associated with whales regarding vessel collisions are discussed in sections 4.6.2.1 and 4.6.2.2 of this EIS.

To investigate the impacts of underwater noise on marine mammals, it is important to understand how they perceive sound and how it affects their physiology. Marine mammals rely on hearing for a wide variety of critical functions, so exposure to sounds that permanently affect their hearing ability poses significant problems for the survival and reproduction of these animals. The two main groups of marine mammals discussed below include cetaceans and pinnipeds. The hearing ability of marine mammals is a function of the following characteristics and processes:

- Absolute Hearing Threshold Curve – The level of a sound that is barely audible in the absence of significant ambient noise is the absolute hearing threshold. This varies with frequency, given a threshold curve with reduced sensitivity at low and high frequencies and maximum sensitivity in an intermediate frequency range. The graph of this information, threshold versus sound frequency is termed an audiogram, which is species-dependent. A behavioral audiogram shows sound levels for each frequency that are both detectable by the species and elicit a specific behavioral response such as moving away from the noise source.

- Individual Variation – Auditory sensitivity varies between individuals. Published audiograms for most species are based on data for only one or two individuals; therefore, audiograms are only an indication of the range of frequencies detectable for a species and the sound levels of each frequency that elicits a behavioral response.

- Masking – Masking is the process by which the hearing threshold for one sound is raised by the presence of another sound, thus competing with important signals (communication) (NRC 2005). Ambient noise often masks the ability of an organism to detect a sound signal, even when that sound is above the hearing threshold. Not only can masking noise prevent the detection of anthropogenic sound sources by marine mammals, but it can also impede sound used by organisms for communication, detecting predators and prey. In general, masking effects are expected to be less severe when sounds are transient than when they are continuous and fixed.

- Localization – Sound source localization is the ability of an organism to determine the direction from which a sound is originating. The ability of marine mammals to localize is important for social interaction and for detecting predators or prey, whether by echolocation or normal listening. It is also important in order to detect a signal of interest amongst a man-made or other noise (Kryter 1985). The precision of localization depends on species, frequency, and other characteristics of the sound (Fay 1988).

- Frequency and Intensity Discrimination – This refers to the ability to discriminate sounds of different frequencies and levels, particularly over ambient noise levels.

As described above, there is individual variation among species and individuals; however, species groups appear to have similar sensitivity to sound. Table 4.5.2.1-2 lists ranges of frequencies to which marine mammal groups are typically sensitive.

TABLE 4.5.2.1-2

**Hearing in Marine Mammals**

| Marine Mammal Group | Examples | Range of Detection | Hz |
|---|---|---|---|
| Pinnepeds – Otariids | Sea lions, fur seals | Mid | 1,000 - 30,000 |
| Pinnepeds – Phocids | True seals, walrus | Low to Mid | 200 - 50,000 |
| Cetaceans – Mysticete | Baleen whales | Low | 10 - 5,000 |
| Cetaceans – Odontocete | Toothed whales | Mid to High | 4,000 - 100,000 (some species detect in excess of 150,000 Hz) |

Source: NOAA Fisheries 2004

Changes in underwater noise levels can cause different behavioral responses in marine mammals. Behavioral responses of marine mammals vary based on the degree and duration of the disturbance. Exposure to very loud sounds by marine mammals may cause avoidance of an area, disruption of echolocation, masking, habitat abandonment, aggression, pup/calf abandonment, annoyance, helplessness, hearing loss, and tissue rupturing (Caltrans 2002). Changes in behaviors such as altered motor behaviors and vocalization characteristics may have both direct energetic costs and potential effects to foraging, navigation, and reproductive activities (Southall 2005).

Avoidance is a typical behavioral response displayed by marine mammals when disturbed by underwater noise, which includes changes in swimming course, in which horizontal movements may become random. Cetaceans have been known to reduce their swimming speeds, digress from travel routes, and otherwise avoid the source of noise disturbances (i.e., quick dives). Cetaceans often dive to deeper depths to avoid humans and boats near the surface, a technique commonly demonstrated by mother-calf pairs. Interruption of feeding, resting, or social activities, and abrupt diving or swimming away constitute possible short-term reactions of mysticetes disturbed by human-made noise (Finley 1982; Calkins 1983). These short-term behavioral responses are in response to broadband industrial and recreational vessel noise extending from below 75 hertz (Hz) to 1,000 Hz (DOSITS 2006).

Marine mammals and sea turtles that occur in the waterway for LNG marine traffic could be affected by short-term and long-term impacts associated with transiting LNG vessels and construction vessels. These impacts and mitigations are discussed at length in sections 4.5.2.2, 4.6.2.1, and 4.6.2.2 of this EIS.

**Other Impacts**

Other potential impacts on aquatic resources resulting from an increase in LNG marine traffic include impingement and entrainment of marine species from operational water intake requirements; thermal and chemical impacts from engine cooling water discharge; the potential to introduce non-native aquatic species; degraded water quality from vessel pollution and debris; and the disruption of fishing activities and other marine-based uses. LNG marine traffic during normal operation would not affect benthic habitat or shellfish.

<u>Impingement and Entrainment</u>

Impingement and/or entrainment of aquatic organisms (including fish eggs and larvae) would likely occur during transit as a result of water withdrawals to support vessel operation requirements. However, because vessels would be drawing water as they transit across deep open waters, the potential impact would be transient and therefore not a significant impact on any particular localized aggregation of aquatic organisms. Section 4.5.2.2 provides a more detailed discussion of impacts from impingement and entrainment during construction and operation of the LNG terminal.

<u>Cooling Water Discharge</u>

Thermal impacts associated with vessel engine cooling discharge waters are also expected to be minor and insignificant. CORMIX modeling conducted by Downeast indicates that vessel engine cooling discharges would result in a maximum 26-square meter plume of water that would dissipate to a change of temperature of approximately 1°C or less warmer than ambient conditions 15 to 30 meters from the discharge source (see Appendix O). Temperature elevations of 1°C above ambient would not likely have an impact on adult or juvenile marine species or their eggs.

The engine cooling water systems of LNG vessels visiting the proposed terminal may include biocides for anti-fouling of engine systems. If biocides are used, the effects to native organisms from discharging cooling waters containing biocides would depend on the type of biocide used. Some biocides could adversely affect aquatic organisms, but we conclude the effects would be minor given its rapid dispersal in the environment. Downeast would have no control over the anti-fouling system used on the visiting LNG vessels.

<u>Accidental Releases and Spills</u>

All commercial vessels are required by law to operate in accordance with the 1978 Protocol of the 1973/78 International Convention for the Prevention of Pollution from Ships (MARPOL). In addition, discharges incidental to the normal operation of non-recreational vessels, 79 feet or greater in length, while in U.S. waters are now subject to CWA permitting through the EPA's Vessel General Permit (VGP). The permit incorporates the Coast Guard's mandatory ballast water management and exchange standards, and provides effluent limits for other types of discharges including deck runoff, bilge water, graywater, and other pollutants. It also establishes specific corrective actions, inspection and monitoring requirements, and recordkeeping and reporting requirements.

Therefore, with the exception of a marine casualty or direct violation of law or an international convention (i.e. MARPOL), we conclude water quality effects associated with the discharge of graywater, blackwater, ballast water, or potential accidental releases while in U.S. waters would be effectively minimized.

<u>Invasive Species</u>

Adverse environmental effects associated with the introduction of exotic/invasive/non-native species through ballast water exchange are not expected, as no ballast water would be discharged while transiting both federal and state waters per the requirements of 33 CFR Part 151, which prohibits the exchange of ballast water within 200 nautical miles of the U.S. shore. Hull fouling is another potential vector for introduction of exotic species; however, operators of commercial vessels have a significant economic interest in maintaining vessel hulls in a clean condition. Even a small amount of hull fouling can reduce the vessel's maximum transit speed and lead to an increase in fuel consumption, as the fouling organisms provide resistance to movement. To prevent fouling and the associated economic costs, operators aggressively implement hull plating preservation and maintenance programs. Furthermore, failure to preserve and maintain hull plating not only raises short-term operation costs but also sets the stage for increased long-term hull maintenance costs. There is a particular sensitivity to this engineering and economic reality regarding commercial vessels operating at the higher end of the sailing rates schedule, as is the case for LNG vessels. In addition to the antifouling measures, fluid dynamics plays a practical role as a barrier to the introduction of invasive species. The amount of water that passes over the hull and through the seachest is a massively large volume. The velocity of the seawater, abrasive by nature, along the hull would be expected to "waterblast" off anything that is not affixed to the hull (e.g., a barnacle).

If fouling does occur despite the preventative systems, Downeast has stated that it is highly unlikely that any exotic species originating from the LNG source areas could biologically survive the variance changes in the marine conditions between the point of LNG origin (predominantly warm to tropical environs in the Mediterranean and Trinidad) and the Downeast

LNG Project site. While the variance changes may reduce the presence of fouling organisms, we do not believe it would eliminate them. However, the Coast Guard has developed practices to address exotic/invasive organisms associated with foreign vessels. The Coast Guard Office of Operating and Environmental Standards has developed Mandatory Practices for All Vessels with Ballast Tanks on All Waters of the United States. The mandatory practices include requirements to rinse anchors and anchor chains during retrieval to remove organisms and sediments at their place of origin and remove fouling organisms from hull, piping, and tanks on a regular basis and dispose of any removed substances in accordance with local, state, and federal regulations. Therefore, we conclude that the introduction of non-indigenous attached organisms via vessel hulls is not likely.

Research and Commercial Fishing

Scoping comments received by the Commission indicated stakeholder concern that the presence of the LNG vessels in the waters of the proposed LNG marine traffic route would inhibit the ability of educational researchers and fishermen to use the area. As discussed further in section 4.7.3 and 4.8.2 of this EIS, impacts to marine activity would be insignificant.

Stakeholders also have expressed concern that LNG vessels travelling within the proposed LNG marine transit routes would result in disruption to normal fishing activities, specifically commercial lobstering, and result in the loss of both fishing gear and access to commercially important fishing areas. The herring fishery is conducted mainly through weirs and purse seins; however, weir locations are close to shore, removed from impacts from vessel traffic, and purse seiners are considered mobile fishing gear. Consultations with local fishermen conducted by Downeast indicate that in general fishermen try to avoid placing fishing gear directly in designated shipping lanes in order to prevent loss of their equipment. However, because there is no designated shipping lane within the Grand Manan Channel or Western Passage, it is likely that LNG vessels could interact with fishing gear along these routes. In order to minimize potential interactions with and loss of fishing gear, Downeast would coordinate with local fishermen, conduct advance mapping of lobster trap locations, and establish planned avoidance routes. In hearings held by the Maine BEP on July 16, 2007, fishermen agreed that coordination with Downeast to establish a recommended transit route through those areas that are heavily fished would alleviate some of the stakeholders concerns. In addition, Downeast in cooperation with the Maine DMR, has met with leading representatives of the local lobster fishery to further define and detail the lobstermen’s key concerns and to confirm the individual lobstermen fishing in any areas potentially affected. This information would be used in Downeast’s ongoing effort to update and revise its Fishermen Communication, Coordination and Compensation Plan, discussed further in section 4.8.2 of this EIS. The Fishermen Communication, Coordination, and Compensation Plan was developed by Downeast to address any potential and unavoidable loss of fishing equipment or income as a result of Downeast LNG terminal operations.

### 4.5.2.2 LNG Terminal

The LNG terminal would be located on an 80-acre parcel on the south side of Mill Cove, and the pier would extend about 3,862 feet northeastward into Mill Cove. Mill Cove is located just south of the confluence of Passamaquoddy Bay and the St. Croix River. The Cove area adjacent to the terminal is characterized by partially exposed to semi-protected marine conditions. Aquatic habitats that exist within the proposed terminal site consist of open water and benthic habitat including intertidal and subtidal habitats. The open water habitat includes all waters ranging from 16 to 68 feet deep at MSL in the project area.

**Existing Resources**

Benthic habitat community types known to occur in the project area are summarized in table 4.5.2.2-1. In general the majority of the intertidal zone within Mill Cove is a mosaic of gravelly sand of varying grade sizes, and fairly homogenous pebbly gravel pavement that support a number of invertebrate species (see discussion below). Tidal fluctuations in intertidal habitats within the vicinity of Mill Cove average about 18 feet. Mill Cove is generally protected from strong winds, such that the intertidal area experiences only moderate to low energy wave action. The subtidal habitats of Mill Cove are generally characterized by substrate that range from pebbly sand to fine mud. Water depths in the subtidal areas of Mill Cove reach a maximum of 54.7 feet at MSL in the location of the proposed pier. Tidal currents in the project area typically range from 0.5 to 1.5 feet per second with a maximum velocity of between 2.5 and 4.0 feet per second.

TABLE 4.5.2.2-1

**Substrates/Benthic Community Types Observed at the Mill Cove Study Area (7-11 November 2005) and Associated Maine DEP Rankings**

| Habitat | Location in Tidal Range | DEP Habitat Ranking | Justification | Notes |
|---|---|---|---|---|
| **Intertidal** | | | | |
| Ledge | Mid | Moderate | B,C,D,E,F,G,H,K,O,S,Y | Mid intertidal ledge supported lush *Ascophyllum* growth. The habitat structure provided by the knotted wrack and stable rock substrate, in association with the grazing surface provided by the ledge added value to this habitat type. |
| Mixed Coarse and Fines | High, Mid, and Low | Low | A,E,F,G,H,I,L,O,P,U,Y | Gravely sand substrates with various concentrations of pebble grade in and out with sand flat in the mid intertidal and comprise the primary grain size class in the narrow, low intertidal. Mussels, amphipods, and barnacles were observed in this habitat. This substrate was primarily unvegetated. |
| Sand Flat | Mid | High | A,B,C,D,E,F,G,H,I,J,L,O,P,T | Sandy substrates with very little gravel supported moderate densities of soft-shelled clams. |
| **Subtidal** | | | | |
| Unconsolidated Sediments | Shallow subtidal | High | A,B,C,D,E,F,G,H,I,J,L,R,T,U,Y,AA | Mud with varying amounts of fine pebble gravel characterized most of the subtidal sites observed. |

**Justifications**

| | | | |
|---|---|---|---|
| A | Nursery ground for commercial species | O | Foraging areas for shorebirds and/or wading birds |
| B | Primary production/oxygen production | P | Shorebird roosting and/or staging areas |
| C | High diversity | Q | Supports terrestrial birds |
| D | High primary and secondary production | R | Supports terrestrial mammals |
| E | Shelter | S | Reduces coastal erosion |
| F | Structure for attachment of settling larvae | T | Supports commercial fisheries |
| G | Food resources for one or more functional groups | U | Supports lobster fishery |
| H | Variety of functional groups represented | V | Supports tourism industry |
| I | Sediment and nutrient sink and/or source | W | Geographically isolated and rare populations of species |
| J | Nutrient recycling | X | Haul out and pupping sites for gray and harbor seals |
| K | Production and export of detritus | Y | Foraging area for waterfowl and/or seabirds |
| L | Habitat dependent species | Z | Nesting habitat for endangered birds |
| M | Rare or endangered animals | AA | Supports anadromous fish |
| N | Rare or endangered plants | | |

Table 4.5.2.2-1 also identifies the habitat function and value classification, as designated by Maine DEP guidance (Ward 1999). Habitat rankings range from low to high for the intertidal substrate types located within the study area. Sand flat substrates located in the mid intertidal generated the highest possible ranking. These areas contribute to the overall 2.1 acres of intertidal substrate in the study area identified as gravelly sand mixtures. Sand flat at this site was observed to support at least one commercially important species, the soft-shelled clam. The actual footprint of the pier would only occupy a small percentage of this area.

Vegetated ledge, which comprised about 15 percent (1 acre) of the intertidal study area's aerial coverage, garnered a moderate value ranking. The balance of the coarser gravelly sand grades fall under the "mixed coarse and fines" Maine DEP designation and is assigned a low value ranking by Maine DEP. Fairly uniform pebble substrate in the mid intertidal comprised 0.3 acre, or 3.9 percent of the study area, and also falls under the Maine DEP designation "mixed coarse and fines." The actual footprint of the pier would only occupy a small percentage of this area.

Subtidal substrates ranging from gravelly sand (very shallow subtidal) to various grades of mud that dominate the study area are designated as unconsolidated sediments by Maine DEP criteria and are ranked as having a high value.

The intertidal and subtidal zones associated with the terminal area supports sparse populations of knotted wrack and kelp, which provides an important source of food for sea urchins and gastropods, as well as habitat for fishes and invertebrates. Eelgrass (*Zostera marina*) was not observed during surveys conducted by Downeast, and has not historically been mapped in Mill Cove. However, eelgrass mapping completed in 2010 by Maine DMR identified eelgrass beds in Mill Cove that were not previously identified by Maine DMR mapping efforts (see section 4.4.2.1).

Both the benthic and open water habitats associated with the terminal project area support a number of marine aquatic resources. These resources are discussed in further detail below. No freshwater fishery resources are associated with the proposed terminal site. Marine vegetation is discussed further in section 4.4 of this EIS.

<u>Invertebrates</u>

Benthic sampling was performed in November 2005 by Downeast at 49 locations (14 intertidal locations and 35 subtidal locations) within the proposed terminal location, in accordance with Maine DEP guidelines (Ward 1999). Additional benthic video surveys also were conducted in August, September, and October of 2007 and March of 2008. The surveys covered a total of approximately 18,100 meters (18.1 kilometers) around the immediate vicinity of the proposed pier, the general area of Mill Cove normally fished for lobsters, and specific areas where oversized and small lobsters reportedly have been found. The specific emphasis of the studies was the areas adjacent to an abandoned weir to the south of the proposed pier and along an active herring weir in the center of Mill Cove north of the proposed project site. Benthic video surveys were conducted in accordance with Maine DMR guidelines.

In the intertidal areas, the substrate consisted of sandy pebbly gravel/gravelly sand and ledge. Species observed in the lower intertidal areas included amphipods, blue mussels, northern rock barnacles (*Semibalanus balanoides*), and periwinkles (*Littorina littorea*). Species observed in the mid intertidal areas included the northern rock barnacles and periwinkles, soft-shelled clams, and several species of polychaete. The high intertidal areas included only a species-poor worm community.

Substrate in the subtidal area between 1.5 to 25 feet mean lower low water (MLLW) ranged from gravelly sand to mud. Mussels and periwinkles were present on coarser substrates, and mud supported amphipod/worm burrows, cerianthid anemones (*Cerianthus borealis*), erect ectoprocts, moon snails (*Nacticidae*), tubularian hydroids (*Tubularia* spp.), northern sea scallops (*Placopecten megellanicus*), American lobster (*Homarus americanus*), and crab (*Cancer* spp.).

Substrates in the subtidal area between 26 to 50 feet MLLW were gravelly mud and fine mud. Species in this area included sponges, fringed anemone (*Metridium senile*), red-gilled nudibranch (*Flebellina* sp.), orange-footed cucumber (*Cucumaria frondosa*), stalked tunicate (*Boltenia ovifera*), green sea urchin (*Strongylocentrotus droebachiensis*), American lobster, cancer crabs, sea vase (*Cliona intestinalis*), sculpin (*Myoxocephalus* spp.), and mysid shrimp (*Mysidacea)*. Patchy stalked tunicate "meadows" supporting individual Boltenia were also observed at two locations in this zone. Substrate in the subtidal area between 51 to 81 feet MLLW was fine mud. Infaunal sampling in this area indicated a species richness that was similar to that observed in water depths ranging from 26 to 50 feet MLLW.

A number of the invertebrate species found within the proposed project area are of commercial and/or recreational importance, including sea scallops, lobsters, soft-shelled clams, periwinkles, and blue mussels. These species are discussed in further detail below.

Several of the species found within Mill Cove are considered invasive exotic species, including the green crab (*Carcinus maenas)* and the common periwinkle.

Pelagic and Demersal Finfish

There are about 500 species of fish found in coastal Maine and nearby Canada, not including 37 species of cartilaginous fish (sharks, skates, rays, and chimaeras). These fish can be generally grouped into demersal or groundfish—those occurring on or close to the bottom including such species as cod, haddock, and pollock; and pelagic—those occurring in the water column usually away from the bottom including such species as herring and mackerel.

Most information about finfish resources in Passamaquoddy Bay and Mill Cove is dated; however, studies conducted by Tyler (1971) at locations near the proposed project area give insight into the abundance and seasonality of the finfish species likely to occur in the project area. These representative demersal and pelagic finfish species are identified in table 4.5.2.2-2. As noted in table 4.5.2.2-2, a number of these demersal and pelagic species are of commercial and/or recreational importance. These species are discussed in more detail below.

Migratory Finfish Species

Anadromous fishes generally spawn in freshwater and mature in marine waters. Anadromous fish would ascend rivers and streams, typically in the late-winter and spring, and spawn in freshwater above the head of tide. Depending upon the species and the life stage, migratory fish tend to travel at different positions within the water column, move at different times of the day, and may or may not overlap with other migratory species. The typical pattern is for a springtime adult in-migration and a fall out-migration of juveniles.

TABLE 4.5.2.2-2

**Representative Finfish and Invertebrate Species Known to Occur in the Project Area**

| Common Name (Scientific Name) | Commercial Fishery | Recreational Fishery | Anadromous | Catadromous | Threatened or Endangered |
|---|---|---|---|---|---|
| **Finfish Species** | | | | | |
| Alewife (Alosa pseudoharengus) | X | | X | | |
| Alligator fish (Aspidophoroides monopterygius) | | | | | |
| American Eel (Anguilla rostrata) | X | | | X | |
| American Plaice (Hippoglossoides platessoides) | | | | | |
| American Shad (Alosa sapidissima) | | X | X | | |
| Atlantic Cod (Gadus morhua) | X | | | | |
| Atlantic Mackerel (Scomber scombrus) | | | | | |
| Atlantic Salmon (Salmo salar) | | | X | | X |
| Atlantic Herring (Clupea harengus harengus) | X | | | | |
| Atlantic sea raven (Hermitripterus americanus) | | | | | |
| Atlantic tomcod (Microgadus tomcod) | | | | | |
| Blueback Herring (Alosa aestivalis) | X | | X | | |
| Daubed Shanny (Leptoclinus maculates) | X | | | | |
| Fourbeard rockling (Enchelyopus cimbrius) | | | | | |
| Grubby (Myoxocephalus aenaeus) | | | | | |
| Haddock (Melangerammus aeglefinus) | | | | | |
| Longhorn sculpin (Myoxocephalus octodecemspinosa) | X | | | | |
| Lumpfish (Cyclopterus lumuis) | | | | | |
| Ocean Pout (Macrozoarces americanus) | | | | | |
| Pollock (Pollachius virens) | | | | | |
| Rainbow Smelt (Osmerus mordax) | X | X | X | | |
| Redfish (*Sebastes* sp.) | | | | | |
| Shorthorn sculpin (Myoxocephalus scorpius) | X | | | | |
| Silver Hake (Merluccius bilinearis) | | | | | |
| Winter Flounder (Pleuronectes americanus) | X | | | | |
| Yellowtail Flounder (Pleuronectes ferruginea) | | | | | |
| **Cartilaginous Finfish Species** | | | | | |
| Little Skate (Leucoraja erinacea) | | | | | |
| Smooth Skate (Malacoraia senta) | | | | | |
| Thorny Skate (Amblyraja radiate) | | | | | |
| Spiny Dogfish (Squalus acanthias) | X | | | | |
| Winter Skate (Leucoraja ocellata) | | | | | |
| **Invertebrate Species** | | | | | |
| American Lobster (Homarus americanus) | X | | | | |
| Blue Mussel (Mytilus edulis) | | | | | |
| Deep Sea Scallop (Placopecten magellanicus) | X | | | | |
| Northern Sea Scallops (Placopecten magellanicus) | X | | | | |
| Common Periwinkles (Littorina littorea) | | | | | |
| Green Sea Urchins (Stronglylocentrotus droebachiensis) | X | | | | |
| Soft-shelled Clams (Mya arenaria) | X | | | | |
| Jonah/Rock Crab (Cancer spp) | | | | | |

As indicated in table 4.5.2.2-2, anadromous fish occurring in the project area include alewife (*Alosa pseudoharengus*), blueback herring (*Alosa aestivalis*), American shad (*Alosa sapidissima*), and rainbow smelt (*Osmerus mordax*). The Atlantic salmon (*Salmo salar*), listed as federally endangered, also has the potential to occur in the general vicinity of the Downeast LNG Project (see section 4.6 of this EIS). The St. Croix River, located just north of Mill Cove, is a significant source of freshwater habitat for many of the migratory fish, and the Western Passage represents a major passageway between Passamaquoddy Bay and the northern Gulf of Maine. As such, many of the migratory species listed above are likely to migrate past the pier during their in- and out-migrations.

Communication with the St. Croix International Waterway Commission has indicated that the migratory striped bass species is known to occur in the waters associated with the project area (including both the terminal and the sendout pipeline). However, data and information obtained from the Atlantic States Marine Fisheries Commission (ASMFC), Maine DMR, and NOAA Fisheries indicated that while striped bass have been caught in the St. Croix River and its associated watershed, this species has been historically scarce in the eastern region of Maine. As such, it is unlikely that construction or operation of the project would adversely impact striped bass.

NOAA Fisheries staff has expressed concern for the blueback herring, currently managed under a fisheries management plan (FMP). Historically, blueback herrings have been reported in abundance in the waters of the St. Croix River. However, legislation passed in 1995 closed the fishway during the spawning season to keep alwives, and consequently bluebacks, out of the upper portions of the river, effectively eliminating the run. As a consequence, the alewife run (including bluebacks) has gone from about 2.8 million adults in the late 1980s to only 800 to 11,000 in recent years (CFN 2005; Tom Squires DMR). Most recently, in April 2013, Maine State Legislature passed a law (LD 72) for fishway barriers to be removed to allow passage of spawning alewives. Removal of barriers would also allow for blueback herring to pass up river. The blueback herring could occur in the project area during migration. However, because the project would not create a barrier to passage up or down the St. Croix River, impacts from the construction and/or operation of the project on blueback herring are not anticipated.

Catadromous species spawn in the ocean and then migrate into freshwater locations for growth and maturation. The American eel (*Anguilla rostrata*) is the only true catadromous species that may occur within the vicinity of the proposed project area.

<u>Commercial and Recreational Species</u>

As indicated in table 4.5.2.2-2, there are 11 finfish and 5 invertebrate species of commercial importance that have historically occurred in the project area. Of these species, the daubed shanny (*Lumpenus maculates*), hake (juvenile), sculpin (*Myoxocephalus* sp.), short-horned sculpin (*Myoxocephalus scorpius*), and winter flounder (*Pleuronectes americanus*) were observed in the subtidal areas of the project site during site surveys conducted in January 2006. Two fishing weirs for Atlantic herring are located in the immediate vicinity of the proposed project. One of these, located immediately north of the proposed pier site, appears to be in functional condition while the southern of the two is apparently abandoned and in disrepair. Despite the cyclical nature of this fish species, fishing weirs in the Cove have experienced a significant decline in catch for many years (Morrison 2006). Both hake (white and red) and winter flounder are considered species with EFH within Passamaquoddy Bay. Detailed descriptions of these species, as well as an analysis of impacts to habitat for these species, as requested by NOAA Fisheries, is included in the EFH Assessment (Appendix G).

Winter flounder is one of the most common shoalwater flounder in the Gulf of Maine and all life history stages are prevalent in the saltwater and brackish water mixing zones within Passamaquoddy Bay. Adult winter flounder occur in depths ranging from 1 to 100 meters, and salinities between 15 and 33 ppt. Spawning winter flounder adults are found in waters with temperatures below 15°C, depths less than 6 meters and salinities between 5.5 and 36 ppt. Spawning occurs in January through May, the optimal temperature being 3.3°C to 5.6°C and optimal salinity 11 to 33 ppt. Temperature dependent migration occurs, although food availability may also be a factor (Pereira et al. 1999). Flounder eggs tend to occur in waters with temperatures less than 10°C, water depths less than 5 meters, and salinities between 10 and 30 ppt; eggs are often observed from February to June. Winter flounder larvae are often observed from March to July. Young-of-the-year occupy bottom habitats with a substrate of mud or fine grained sand, within waters where the temperature is below 28°C, depths from 0.1 to 10 meters, and salinities ranging between 5 and 33 ppt. Age 1-plus juvenile are found in inshore areas in waters with temperatures below 25°C, depths from 1 to 50 meters, and salinities between 10 to 30 ppt.

Potential impacts on winter flounder near the terminal include construction related lighting, noise, increased sedimentation and turbidity associated with pile driving and hydrostatic testing of storage tanks, as well as operational impacts including entrainment/impingement of juvenile winter flounder during LNG vessel ballast water uptake or engine cooling, shading from the trestle and platform, and loss of eelgrass habitat. Installation of the pier would disturb and occupy a very limited area (4,885.5 square feet or 0.1 acre) of bay floor, removing only a selected portion of the benthic community immediately underlying and/or adjacent to each pile. Additionally, as described in section 4.3.2.1, suspended sediments from pile driving does not typically result in the release of a substantial amount of sediment into the water column. The proposed LNG terminal is in an area known to be utilized by winter flounder for spawning and feeding. Comment letters during the scoping process have expressed concern for winter flounder adults, juveniles, and larvae near the LNG terminal. Operational impacts are discussed in greater detail below. Impacts on winter flounder in the project area would be similar to those detailed for all EFH species in Appendix G.

Other commercial species of importance known to occur in the vicinity of the project area consist of invertebrate species, including American lobster, green urchins, soft-shelled clams, and sea scallops. Interviews with local fishermen indicate that many of the commercial fisheries in Mill Cove have declined in recent years. In addition, as of January 17, 2007, Maine DMR closed the northwest portion of Mill Cove to the harvest of clams, quahogs, oysters, mussels, and other marine mollusks because of pollution. Despite this decline, lobstering in Mill Cove is currently still active. According to local fishermen, there are six to eight lobstermen who fish the area between Perry and Calais on a regular basis, and two to three lobstermen who set traps regularly near Mill Cove (Morrell 2006). According to Town of Robbinston officials, there are only two lobstermen who regularly lobster the Mill Cove area setting up to 15 to 30 traps in and near the Mill Cove area (Stanhope 2005; Moholland 2005; Morrell 2006). During a trap survey conducted October 1, 2006, eight lobster traps were observed within Mill Cove near the northern fishing weir and an equal number were set immediately outside of Mill Cove in the main waterway.

Site-specific information regarding the overall abundance of lobster and value of the associated fishery in Mill Cove as well as the greater Passamaquoddy and Cobscook Bays currently is not well characterized (Maine DMR 2007). However, in the last 10 years, both the population and fishery have experienced a period of rapid growth. In 2012, new lobster regulations for the Gulf of Maine regulated the maximum number of traps (800) per permit and instituted a limited entry program for the fishery (50 CFR Part 697). This rule effectively sustains fishing effort at current levels to prevent growth of the fishery that could lead to overfishing. Lobstering currently accounts for nearly 75 percent of the value of Maine's marine resources and according to the Maine DMR, greater than 50 percent of the recent increase in lobster trap tags issued in the last 10 years has been in the zone that encompasses the proposed project area. Given stakeholder concern for potential project impacts on the lobster fishery in Mill Cove, which local fishermen have indicated is a significant habitat for juvenile and egg-bearing lobsters, Downeast initiated an extensive monthly benthic video monitoring survey to assess overall fisheries composition, a lobster trapping study to investigate local lobster population size and composition, and a lobster tagging study to track the movements of lobsters within Mill Cove and beyond. A detailed description of these surveys can be found in Appendix O. These subtidal studies and functional assessments were conducted in August, September, and October of 2007 and March, May, June, July, and September of 2008, in accordance with the Survey Requirements for Proposed Dredging in Subtidal Areas developed by the Maine DMR. Video surveys covered approximately 38,330 meters (38.3 kilometers) in the general area of Mill Cove and points both north and south normally fished for lobsters and specific areas where oversized and small lobsters have been reportedly found, with emphasis on the areas adjacent to an abandoned weir to the south of the proposed pier and along an active herring weir in the center of Mill Cove north of the proposed project site. The survey area is shown in figure 4.5-1.

Maine DMR guideline density for important lobster habitat is 0.1 lobster/$m^2$. The largest concentrations of lobsters found within the study area running from Active Weir 2 at the south to Red Beach at the north are generally found in association with weirs (Active Weir 1 [up to 0.190 lobster/$m^2$], Active Weir 2 [up to 0.190 lobster/$m^2$], Abandoned Weir Mill Cove [up to 0.160 lobster/$m^2$], and in the vicinity of Loring Cove [up to 0.142 lobster/$m^2$]). The high lobster density found in the rock/boulder habitat in the vicinity of Loring Cove is consistent with the higher fishing effort (larger number of traps) observed in this area compared to the other sections of the shoreline. In 2007 and 2008, video surveys indicated that lobsters observed at the abandoned weir south of the proposed pier are predominantly large or oversized, eggbearing females. Lobsters observed over firmer rock and cobble substrate along the north shoreline of Mill Cove are generally small, juvenile lobsters usually found under rocks. Lobsters observed along the Perry shoreline are of varying sizes, although these are generally large lobsters and when found around weirs are large, oversized, reproductive lobsters (primarily eggbearing females) similar to the population found at the abandoned weir in Mill Cove.

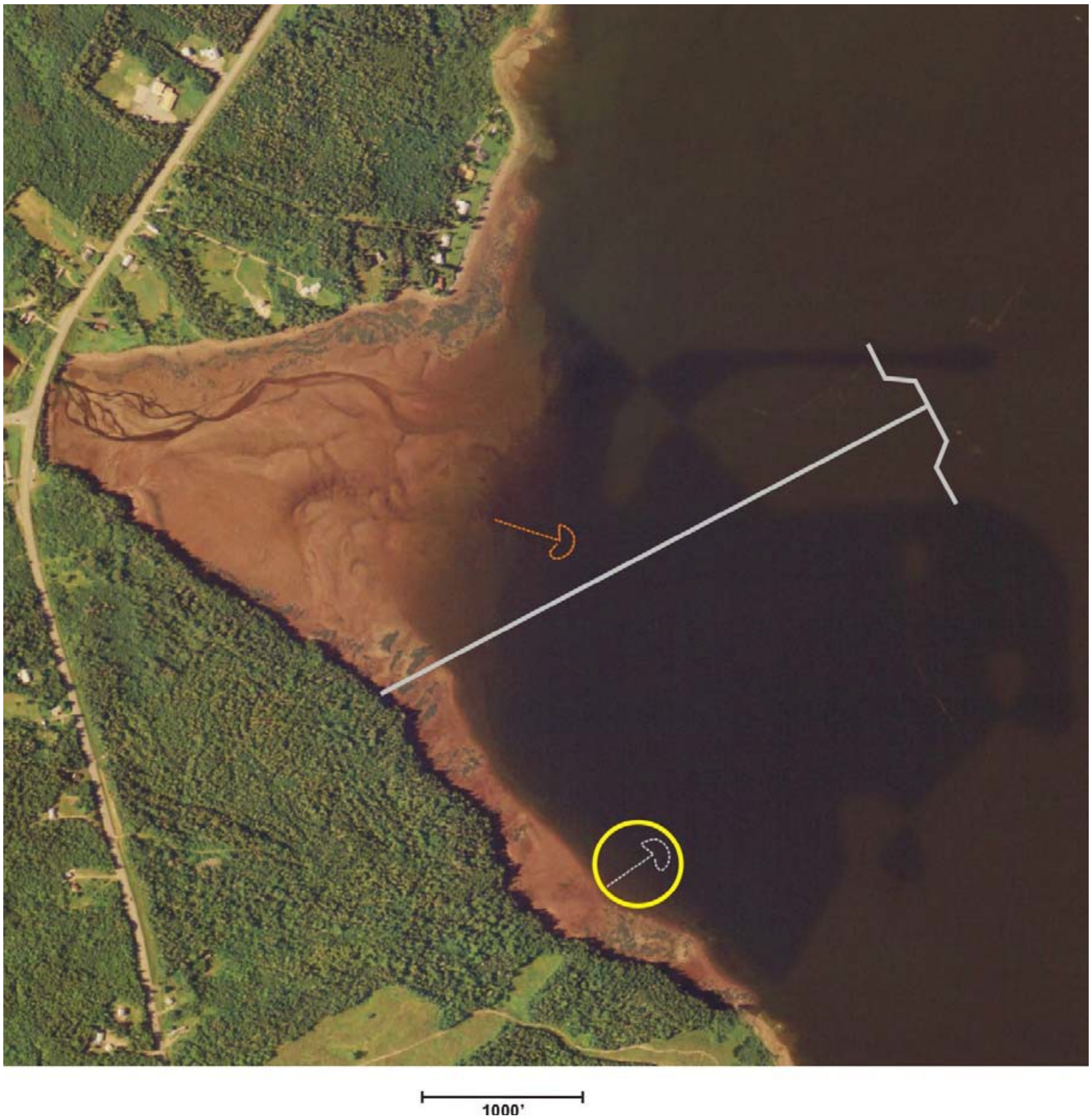


**Figure 4.5-1**
**Downeast LNG Project**
**Mill Cove Lobster Survey Area**

Downeast also conducted a lobster trap study in Casco Bay in September 2007 and in Mill Cove between September and October 2007 and again between August and November 2008. Survey design included standard commercial lobster traps, modified traps (small mesh and closed vents), and oversized traps. Despite the relatively short survey period in Casco Bay, the number of lobsters caught (433 lobsters), as well as the catch per unit effort (3.7 lobsters/trap haul) in the Bay, was significantly greater than the total numbers caught (239 lobsters) and catch per unit effort (0.54 lobsters/trap haul) over the study period in Mill Cove (see table 4.5.2.2-3).

Downeast is also conducting an ongoing lobster tagging study of lobsters caught in the study traps to determine species movement and sight fidelity. All lobsters caught in the 2007 and 2008 study traps were tagged with a yellow rubber band, bearing an ID number and reporting phone number, applied to the “knuckle” (joint) below the right-hand claw. In over-sized lobsters, however, when the band could not be stretched enough to go over the claw, the band was applied to a tail fin, or uropod, usually second from right. Two banded lobsters were recaptured and reported in 2007: #22, a female lobster weighing approximately 1.3 pounds, caught on September 30 just north of Loring Cove, and #62, a male lobster weighing approximately 1.5 pounds, caught on December 30 off of the “factory” in Robbinston. No lobsters were reported recaptured in 2008.

No tags were applied in 2009. In 2010 the yellow bands were replaced with Stoffel Seal EQUILOX seals. Different colors were used to identify lobsters caught along the shoreline, each color corresponding to a section of the Western Passage to Red Beach and the St. Croix River shoreline. However, fishing activities were focused on the area between (from north to south) McCurdy Point and Lewis Cove. As a result, only yellow and green tags were deployed. Four tagged lobsters were re-captured within the study area during 2010 sampling.

Additionally, a sonar tagging program was started in 2010 to apply sonar transmitting tags on selected large reproductive lobsters from the abandoned weir population in Mill Cove. These tags are tracked using either portable or fixed receivers to study short-distance movement behavior of the lobsters for further determination of habitat fidelity. A total of 10 lobsters consisting of six females, four of which were egg-bearing, and four males, all ranging in size from 123 mm to 202 mm carapace length (CL), were collected by a SCUBA diver, tagged, and released to their original location on August 25, 2010. Data from the remote sensing buoy were downloaded on nine occasions between September 2, 2010 and November 12, 2010. Manual tracking was conducted on eight occasions between September 2, 2010 and December 10, 2010.

The tagged lobsters initially showed no consistent behavior with respect to movement, depth, temperature, or time of departure from the immediate vicinity of the abandoned weir. However, when water temperature had dropped to near 12$^{o}$C in October 2010, all detected lobsters were found in progressively deeper water ranging between 20 meters (66 feet) and nearly 73 meters (240 feet) in depth. Distance traveled also varied considerably. Based on the final position for all lobsters, the four lobsters last detected within the vicinity of Mill Cove had traveled an average distance of 1.4 kilometer from the initial point of tagging with a range of 440 meters to 1.64 kilometer; it should be noted that only one of these lobsters was found to be remaining in the vicinity of Mill Cove on the last detection date, December 10, 2010.

TABLE 4.5.2.2-3

**Lobster Catch Data and Indices for Mill Cove with Comparison Catch Data from Casco Bay**

| | Legals | Subleg | Notched | Egged | Total | # traps | #/trap haul | Nite set | #/trap haul/n-s | Lgl/trap | Sub/trap | N-E/trap | M | F | M-F % | | M:F | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Mill Cove Haul Data Summary** | | | | | | | | | | | | | | | | | | |
| 9/10/07 | 1 | 4 | 0 | 0 | 5 | 24 | 0.21 | 1 | 0.21 | 0.042 | 0.167 | 0.000 | 2 | 3 | 40.0% | 60.0% | 1.0 | 1.5 |
| 9/11/07 | 2 | 9 | 0 | 0 | 11 | 23 | 0.48 | 1 | 0.48 | 0.087 | 0.391 | 0.000 | 7 | 4 | 63.6% | 36.4% | 1.0 | 0.6 |
| 9/12/07 | 4 | 5 | 0 | 0 | 9 | 23 | 0.39 | 1 | 0.39 | 0.174 | 0.217 | 0.000 | 6 | 3 | 66.7% | 33.3% | 1.0 | 0.5 |
| 9/19/07 | 6 | 6 | 0 | 0 | 12 | 27 | 0.44 | 7 | 0.06 | 0.222 | 0.222 | 0.000 | 8 | 4 | 66.7% | 33.3% | 1.0 | 0.5 |
| 9/26/07 | 8 | 2 | 0 | 0 | 10 | 25 | 0.40 | 7 | 0.06 | 0.320 | 0.080 | 0.000 | 7 | 3 | 70.0% | 30.0% | 1.0 | 0.4 |
| 10/4/07 | 6 | 3 | 0 | 0 | 9 | 26 | 0.35 | 8 | 0.04 | 0.231 | 0.115 | 0.000 | 6 | 3 | 66.7% | 33.3% | 1.0 | 0.5 |
| 10/10/07 | 7 | 2 | 0 | 0 | 9 | 26 | 0.35 | 6 | 0.06 | 0.269 | 0.077 | 0.000 | 7 | 2 | 77.8% | 22.2% | 1.0 | 0.3 |
| 10/17/07 | 4 | 8 | 1 | 0 | 13 | 25 | 0.52 | 7 | 0.07 | 0.160 | 0.320 | 0.040 | 8 | 5 | 61.5% | 38.5% | 1.0 | 0.6 |
| 10/29-31/07 | 6 | 2 | 0 | 0 | 8 | 34 | 0.24 | 12 | 0.02 | 0.176 | 0.059 | 0.000 | 4 | 4 | 50.0% | 50.0% | 1.0 | 1.0 |
| All dates | 44 | 41 | 1 | 0 | 86 | 233 | 0.37 | 5.6 | 0.15 | 0.191 | 0.178 | 0.004 | 55 | 31 | 64.0% | 36.0% | 1.0 | 0.6 |
| 8/23/08 | 32 | 0 | 6 | 6 | 32 | 24 | 1.33 | 6 | 0.22 | 1.33 | 0.00 | 0.25 | 16 | 16 | 50.0% | 50.0% | 1.0 | 1.0 |
| 8/30/08 | 16 | 8 | 7 | 7 | 24 | 24 | 1.00 | 7 | 0.14 | 0.67 | 0.33 | 0.29 | 8 | 16 | 33.3% | 66.7% | 1.0 | 2.0 |
| 9/6/08 | 11 | 7 | 6 | 6 | 18 | 22 | 0.82 | 6 | 0.14 | 0.50 | 0.29 | 0.27 | 7 | 11 | 38.9% | 61.1% | 1.0 | 1.6 |
| 9/13/08 | 11 | 16 | 5 | 5 | 27 | 23 | 1.17 | 7 | 0.17 | 0.48 | 0.67 | 0.22 | 13 | 14 | 48.1% | 51.9% | 1.0 | 1.1 |
| 9/20/08 | 15 | 8 | 7 | 7 | 23 | 23 | 1.00 | 7 | 0.14 | 0.65 | 0.33 | 0.30 | 9 | 14 | 39.1% | 60.9% | 1.0 | 1.6 |
| 10/11/08 | 7 | 7 | 4 | 4 | 14 | 24 | 0.58 | 21 | 0.03 | 0.29 | 0.29 | 0.17 | 4 | 10 | 28.6% | 71.4% | 1.0 | 2.5 |
| 10/19/08 | 6 | 5 | 3 | 3 | 11 | 24 | 0.46 | 16 | 0.03 | 0.25 | 0.21 | 0.13 | 5 | 6 | 45.5% | 54.5% | 1.0 | 1.2 |
| 11/5/08 | 2 | 1 | 0 | 0 | 3 | 24 | 0.13 | 16 | 0.01 | 0.08 | 0.04 | 0.00 | 2 | 1 | 66.7% | 33.3% | 1.0 | 0.5 |
| 11/11/08 | 0 | 1 | 0 | 0 | 1 | 24 | 0.04 | 6 | 0.01 | 0.00 | 0.04 | 0.00 | 1 | 0 | 100.0% | 0.0% | 1.0 | 0.0 |
| All dates | 100 | 53 | 38 | 38 | 153 | 212 | 0.72 | 10.2 | 0.10 | 0.47 | 0.25 | 0.18 | 65 | 88 | 42.5% | 57.5% | 1.0 | 1.4 |
| 7/3/2010 | 16 | 6 | 0 | 2 | 25 | 81 | 0.31 | - | - | 0.20 | 0.07 | 0.00 | 12 | 13 | 48.0% | 52.0% | 1.0 | 1.1 |
| 7/10/2010 | 19 | 3 | 0 | 2 | 25 | 82 | 0.30 | 6 | 0.05 | 0.23 | 0.04 | 0.00 | 14 | 11 | 56.0% | 44.0% | 1.0 | 0.8 |
| 7/17/2010 | 18 | 2 | 1 | 0 | 22 | 83 | 0.27 | 6 | 0.04 | 0.22 | 0.02 | 0.01 | 14 | 8 | 63.6% | 36.4% | 1.0 | 0.6 |
| 7/24/2010 | 41 | 6 | 0 | 0 | 47 | 82 | 0.57 | 6 | 0.10 | 0.50 | 0.07 | 0.00 | 28 | 19 | 59.6% | 40.4% | 1.0 | 0.7 |
| 7/31/2010 | 62 | 6 | 1 | 3 | 72 | 86 | 0.84 | 6 | 0.14 | 0.72 | 0.07 | 0.01 | 46 | 26 | 63.9% | 36.1% | 1.0 | 0.6 |

TABLE 4.5.2.2-3

**Lobster Catch Data and Indices for Mill Cove with Comparison Catch Data from Casco Bay**

| | Legals | Subleg | Notched | Egged | Total | # traps | #/trap haul | Nite set | #/trap haul/n-s | Lgl/trap | Sub/trap | N-E/trap | M | F | M-F % | | M:F | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8/7/2010 | 84 | 7 | 0 | 0 | 91 | 83 | 1.10 | 6 | 0.18 | 1.01 | 0.08 | 0.00 | 59 | 32 | 64.8% | 35.2% | 1.0 | 0.5 |
| 8/14/2010 | 114 | 5 | 3 | 2 | 124 | 80 | 1.55 | 6 | 0.26 | 1.43 | 0.06 | 0.04 | 72 | 52 | 58.1% | 42.0% | 1.0 | 0.7 |
| 8/21/2010 | 140 | 13 | 0 | 6 | 160 | 81 | 1.98 | 6 | 0.33 | 1.73 | 0.16 | 0.00 | 106 | 54 | 66.3% | 33.8% | 1.0 | 0.5 |
| 8/28/2010 | 102 | 8 | 2 | 7 | 119 | 82 | 1.45 | 6 | 0.24 | 1.24 | 0.10 | 0.02 | 67 | 52 | 56.3% | 43.7% | 1.0 | 0.8 |
| 9/6/2010 | 105 | 15 | 1 | 16 | 127 | 75 | 1.69 | 8 | 0.21 | 1.40 | 0.20 | 0.01 | 66 | 61 | 52.0% | 48.0% | 1.0 | 0.9 |
| 9/11/2010 | 113 | 25 | 2 | 7 | 147 | 79 | 1.86 | 4 | 0.47 | 1.43 | 0.32 | 0.03 | 64 | 83 | 43.5% | 56.5% | 1.0 | 1.3 |
| 9/18/2010 | 108 | 15 | 2 | 3 | 127 | 76 | 1.67 | 6 | 0.28 | 1.42 | 0.20 | 0.03 | 68 | 59 | 53.5% | 46.5% | 1.0 | 0.9 |
| 9/27/2010 | 82 | 6 | 2 | 4 | 99 | 78 | 1.27 | 7 | 0.18 | 1.05 | 0.08 | 0.03 | 54 | 45 | 54.6% | 45.5% | 1.0 | 0.8 |
| 10/3/2010 | 52 | 9 | 0 | 2 | 67 | 74 | 0.91 | 5 | 0.18 | 0.70 | 0.12 | 0.00 | 39 | 28 | 58.2% | 42.0% | 1.0 | 0.7 |
| 10/9/2010 | 50 | 9 | 1 | 3 | 64 | 76 | 0.84 | 5 | 0.17 | 0.66 | 0.12 | 0.01 | 31 | 33 | 48.4% | 51.6% | 1.0 | 1.1 |
| 10/17/2010 | 49 | 5 | 0 | 3 | 58 | 71 | 0.82 | 7 | 0.12 | 0.69 | 0.07 | 0.00 | 24 | 34 | 41.4% | 58.6% | 1.0 | 1.4 |
| 10/24/2010 | 33 | 7 | 1 | 6 | 46 | 65 | 0.71 | 6 | 0.12 | 0.51 | 0.11 | 0.02 | 22 | 24 | 47.8% | 52.2% | 1.0 | 1.1 |
| 10/31/2010 | 21 | 0 | 0 | 0 | 22 | 33 | 0.67 | 6 | 0.11 | 0.64 | 0.00 | 0.00 | 14 | 8 | 63.6% | 36.4% | 1.0 | 0.6 |
| All dates | 1209 | 147 | 16 | 66 | 1442 | 1367 | 1.05 | 6 | 0.18 | 0.88 | 0.11 | 0.01 | 800 | 642 | 55.5% | 44.5% | 1.0 | 0.8 |
| **Comparison Haul Data Summary from Casco Bay** | | | | | | | | | | | | | | | | | | |
| 9/20/07 | 17 | 150 | 15 | 4 | 182 | 45 | 4.0 | 4 | 1.01 | 0.378 | 3.333 | 0.333 | 41 | 140 | 22.7% | 77.3% | 1.0 | 3.4 |
| 9/21/07 | 36 | 197 | 19 | 12 | 252 | 71 | 3.5 | 4 | 0.89 | 0.507 | 2.775 | 0.268 | 86 | 166 | 34.1% | 65.9% | 1.0 | 1.9 |
| All dates | 53 | 346 | 34 | 16 | 433 | 116 | 3.7 | 4.0 | 0.95 | 0.457 | 2.983 | 0.293 | 127 | 306 | 29.3% | 70.7% | 1.0 | 2.4 |

Lobster larvae sampling was conducted on five occasions in 2008 using a surface layer sampling neuston net. Over the five sampling events, only two larvae were caught, one Stage I and one Stage IV, from the 18,503 $m^3$ of water sampled, yielding a larval density of 0.00011 larva/$m^3$.

We believe the impacts on both the lobster fishery and lobster fishing industry from the construction and operation of the LNG terminal in Mill Cove would be relatively minor (see also section 4.8.2.5). However, to ensure impacts on the lobster industry are minimized, Downeast in cooperation with the Maine DMR is developing a Fishermen Communication, Coordination and Compensation Plan, described further in section 4.5.2.1 above, and in section 4.8.2 of this EIS. Data does indicate that the area supports numerous large, egg-bearing females. However, video transects along the pier vicinity and the expanded area beyond the pier resulted in average linear densities of 0.003 and 0.032 lobsters per 100 meters, respectively. Habitat within the footprint of the pier would be permanently altered where pilings are installed; however, it is expected that such impact would be minor and that lobsters, being highly mobile, would continue to utilize Mill Cove after construction and throughout the operational life of the proposed facilities. Because Downeast has not yet finalized its Fishermen Communication, Coordination and Compensation Plan; **we recommend that:**

- **Downeast should continue to consult with NOAA Fisheries, Maine DMR, other appropriate agencies, and appropriate representatives of the local lobster fishery to determine impacts on the local lobster population and any recommended mitigations to minimize impacts on lobster and lobster habitat during all proposed construction and operational activities at the LNG terminal. <u>Prior to the start of construction of the LNG terminal facilities</u>, Downeast should file with the Secretary, for review and written approval by the Director of OEP, its final Fishermen Communication, Coordination and Compensation Plan, including copies of its correspondence with consulted agencies and a description of any mitigation measures it has agreed to implement.**

When this information is filed with the Commission, FERC staff will consult with respective agencies as needed during its review.

Finfish aquaculture and the harvesting of marine worms is also an important commercial activity within the vicinity of the project area, in particular along the United States/Canadian border of the proposed LNG marine traffic route. These commercial activities are discussed in greater detail in see section 4.5.2.1 of this draft EIS.

To date, the extent of recreational fishing activities within Mill Cove and the project area are not well quantified; however, observations of the site by Downeast from 2004 to October 2006 indicate that recreational activity is extremely limited, likely due to the large extent of the intertidal area exposed at low water and the strong tidal currents at the site. Downeast confirmed these observations with town representatives. Of the 39 species identified in table 4.5.2.2-2 that could potentially occur in the vicinity of the project, Atlantic cod, Atlantic mackerel, Atlantic salmon, haddock, pollock, shad, and winter flounder are among the species generally known to be targeted by recreational fishermen in other coastal Maine waters.

Zooplankton and Ichthyoplankton

The zooplankton community comprises a diverse assemblage of essentially microscopic free-floating animals, with most marine invertebrate phyla represented as eggs, larvae, or adults. Zooplankton feed on phytoplankton, detritus, and other zooplankton, and provide a link between the primary production of the ocean (i.e., phytoplankton) and the higher trophic levels in the food web. Predators of zooplankton include fish, shellfish, whales, and other zooplankton. Most zooplankton are capable of movement within the water column and some species show a strong diurnal vertical migration in and out of the photic zone, while others tend to augment wind and tidal currents by “swimming” to move laterally throughout bays and coastal environments.

Within the Gulf of Maine region, seasonal zooplankton cycles are related primarily to fluctuations in temperature, rather than light and nutrients, as is the case for phytoplankton (Kropp et al. 2003). Zooplankton abundances are highest in mid-summer, lower in the spring and fall, and typically reach lowest levels in late winter, with variable seasonal trends for individual species.

The Maine DMR currently does not monitor zooplankton within the immediate Downeast project area. The nearest sampling station for zooplankton is located in the vicinity of Grand Manan Island located at 44º55’48”N, 66º51’00”W (approximately 15 miles southeast of the project area) and is maintained by the Canadian Department of Fisheries and Oceans (DFO) as part of its Atlantic Zone Monitoring Program (AZMP). Based on a review of the data collected at this station from 1999 through 2002, the four-year mean zooplankton abundance is 1,579/$m^3$. Copepod mean density is 1,230 per $m^3$ of which *Calanus finmarchicus*, an important contributor to the annual zooplankton biomass cycle and highly abundant copepod species, comprises 5 percent.

In addition to invertebrate zooplankton, the planktonic eggs and larvae of many fish species, known as ichthyoplankton, also make up a portion of the plankton community within the project region. Existing data on ichthyoplankton composition, distribution, and abundance in Passamaquoddy Bay are sparse. Currently, the Maine DMR does not conduct ichthyoplankton monitoring within Cobscook Bay, Western Passage, or the area within Passamaquoddy Bay. The Maine DMR does, however, include ichthyoplankton monitoring as part of its annual inshore trawl survey. The proposed terminal is approximately 22 miles from the nearest Maine DMR sampling location off of Gouldsboro Bay and within Grand Manan Channel.

Downeast conducted on-site sampling for ichthyoplankton and zooplankton from October 2006 through November 2008. Following Maine DMR protocols, preliminary sampling tows were made during the day at low tide and high tide and at night during low tide, both at 30 to 35 feet, coinciding with the anticipated ship seawater intake depth, and as composites of bottom, mid, and surface depths. Results of preliminary on-site sampling conducted in October 2006 indicate fish larvae are present predominantly at night with Atlantic herring being the dominant fish larvae at a nighttime density (averaged between the target and composite depths) of 0.128 larvae/$m^3$ (97.0 percent of all larvae), very similar to the density of 0.123 larvae/$m^3$ (89.8 percent of all larvae) found by Maine DMR during their above-mentioned trawl survey efforts conducted in October 2001. The similarity of these results to the previous Maine DMR inshore trawl survey sampling suggests that the Maine DMR Region 5 data may be substantially representative of the Passamaquoddy Bay area.

Additional on-site sampling was conducted in February, May, August, September, and October of 2007 and February, June, July, August, and November of 2008 in accordance with a site-specific Ichthyoplankton and Zooplankton Sampling Protocol developed in coordination with NOAA Fisheries and the EPA, and submitted by MER Assessment Corporation to Downeast in January 2007 in anticipation of implementation of the protocol in February 2007 (see Appendix O for a copy of the protocol).

Results of the on-site ichthyoplankton sampling, as summarized in the Interim Report (see Appendix O), indicate that fish larvae are most abundant predominantly in the afternoon samples with zooplankton most abundant during nighttime sampling. Fish larvae species assemblages were variable throughout the year with snake blenny (*Lumpenus lampretaeformis*) and winter flounder (*Pseudopleuronectes americanus*) being the dominant larval species in spring, the radiated shanny (*Ulvaria subbifurcata*) in summer, the fourbeard rockling (*Enchelyopus cimbrius*) and Atlantic herring (*Clupa harengus*) in the fall, and Atlantic seasnail (*Liparis atlanticus*) dominant in winter. In general, zooplankton species composition also varied by season with copepods being dominant in all seasons. Spring abundance was highest for calanoid copepods and crustacean larvae. This pattern continued through summer where abundance of most copepods was much greater (two to four times) in late summer. During fall, copepods again became the dominant species. In winter, abundance was considerably less than previous seasons; however, copepods were most abundant.

Detailed results of the ichthyoplankton and zooplankton sampling efforts, conducted in accordance with the sampling plan through November 2008, as reported by Downeast's Interim Report, can be found in Appendix O.

<u>Marine Mammals and Sea Turtles</u>

Several marine mammals and sea turtles have been identified as occupants or migrants within the waters where LNG vessels would be docked. Specifically, harbor seals, gray seals, and harbor porpoise are considered year-round residents in Passamaquoddy Bay, as well as islands and coastline of the surrounding areas, and are likely to be present in the vicinity of the proposed terminal. Other species of marine mammals are not expected to occur within Mill Cove; however, transient individuals could use areas adjacent to the proposed terminal pier. Threatened and endangered species as well as those protected by the MMPA that could occur in the vicinity of the pier are discussed in section 4.6 of this EIS.

Leatherback turtles are known to inhabit the waters of Passamaquoddy Bay and the Bay of Fundy during the summer and fall (typically June through October) and could be affected by the construction and operation of the Downeast LNG terminal. This species of sea turtle is currently listed as endangered by both the United States and Canada. Information regarding this species, including potential impacts and proposed mitigation measures associated with the project, are discussed in section 4.6 of this EIS.

**Construction Impacts**

<u>Turbidity</u>

Construction of the LNG terminal would involve the installation of the pier and berthing facilities within Mill Cove. Organisms in the vicinity of the proposed project area would be affected by construction activities. Specifically, pier construction could contribute to water quality degradation through increased turbidity. The resuspension of sediments during pier installation activities, including propeller wash from construction vessels, could cause increased turbidity resulting in reduced light penetration and hence reduction in primary productivity. Turbidity can also cause an increase in biological oxygen demand resulting in decreased dissolved oxygen concentrations available to fish in and around the affected area. Low dissolved oxygen concentrations can also negatively affect organisms that are an important resource base in fish habitat. Turbidity would reduce visibility thus affecting the ability of sight feeders to locate prey. Those organisms in the immediate footprint of the pier piles with little or no mobility would suffer some mortality. Filter feeding organisms may experience clogging from construction-related suspended sediment. Finfish may also experience similar gill clogging effects; however, this should be a relatively minor impact given the tidal flushing in the area.

<u>Noise</u>

Noise generated from tugboats, operation of barge-mounted equipment, and pile driving during LNG terminal construction could affect fish, marine mammals, pinnipeds, and sea turtles if present during construction activities. Section 4.6.2 of this EIS further describes noise impacts on listed species and marine mammals. Section 4.11.2 of this EIS provides additional discussion of some of the basic acoustics associated with underwater noise and discusses Downeast's underwater acoustic modeling analysis. In a filing with the Commission on May 3, 2013 Downeast stated that based on current design and engineering the project could be constructed using only vibratory hammering for pile driving, and committed to the singular use of vibratory hammering for the installation of piles. Use of vibratory hammering, rather than impact hammering, would reduce underwater noise (see section 4.11.2).

Sounds of short duration that are produced intermittently or at regular intervals, such as sounds from pile driving, are classified as "pulsed." Sounds produced for extended periods, such as sounds from generators, are classified as "continuous." Although continuous noise sources (tugboats, operation of diesel-powered construction equipment) have the potential to elicit certain behavioral effects to marine species, it is impact pile driving that has the greatest potential to cause harassment or injury through generation of intense underwater sound pressure waves. Large diameter steel pipe piles are anticipated to be used to support the trestle and loading platform. These piles would be vibrated through any surficial soils on the seabed to the top of the underlying rock. Driving hollow steel piles with impact hammers produce intense, sharp spikes of sound that can easily reach levels that injure fish. Conversely, vibratory hammers produce sounds of lower intensity, with a rapid repetition rate.

In discussing the impacts of sound on aquatic resources, it is important to note the difference in sound intensity in air versus water. Sound intensity in air uses a standard of 20 micropascals (µPa), while sound intensity measured in water uses a standard level of 1 µPa. Sound sources are typically presented as sound pressure levels at a distance of 1 meter from an idealized point source, i.e., decibels (dB) re 1 µPa at 1 meter.

The intensity of the sound pressure levels produced during pile driving depends on a variety of factors including, but not limited to, the type and size of the pile, the firmness of the substrate into which the pile is being driven, the depth of water, the type and size of the pile-driving hammer, and the geometry and boundaries of the surrounding underwater environment. During impact pile driving, the maximum in-air sound levels upon impact can range from 105 to

115 dBA at 50 feet. The sound frequency generated upon impact is typically 9 kilohertz. In water, the frequency component of pile driving varies with principal energy found in the 200 to 400 Hz range. Impact pile driving source levels well in excess of 200 dB (re: 1 μPa) at 1 meter have been documented from similar construction projects.

Although the effects of pile driving are poorly studied and there appears to be substantial variation in a species' response to sound, intense sound pressure waves can change fish behavior or injure/kill fish through rupturing swim bladders or causing internal hemorrhaging (NOAA Fisheries 2005; Hastings and Popper 2005). Potential effects of noise on marine mammals include masking, disturbance (behavioral), hearing impairment, and non-auditory physiological effects. Noise impacts on marine mammals are discussed further in section 4.6.2 of this EIS and the BA.

The degree to which marine species are exposed to and affected by sound waves is dependent upon variables such as the peak sound pressure level and frequency as well as the species and size (e.g., small fish appear to be more susceptible to injury by intense sound waves than are larger fish of the same species). Short-term exposure to peak sound pressure levels above 190 dB (re: 1 μPa) are thought to physically harm fish (Hastings 2002). For pulsive sounds, NOAA Fisheries requires that individual whales not be exposed to received levels of over 180 dB re 1 μPa (root mean square) and pinnipeds to levels over 190 dB to protect the animals from damaging noise levels. Received levels of over 160 dB may cause disturbance or "Level B" harassment. The effects of underwater noise on sea turtles are not well studied. There are no safety criteria for sea turtles similar to those used by NOAA Fisheries for marine mammals.

The presence of predators can also influence how marine species might be affected by pile driving (e.g., fish stunned by pile-driving activities may be more susceptible to predators). If drilling and/or vibropiling were to occur during anadromous fish migrations, the avoidance of the nearshore areas could restrict migrating fish to deepwater areas that are less suitable for some species, which could increase the susceptibility of some smaller species to predation.

Unlike fish with swim bladders, or marine mammals with ears, most benthic invertebrates are unlikely to be susceptible to tissue damage from most common construction noise levels as the energy would pass through their bodies. Marine invertebrates do not hear noise in the same way that vertebrates do, rather they detect pressure changes, usually at fairly close range. Sound pressure waves passing through the water or sediments may create a localized avoidance response in those benthos that are sensitive to disturbance; however, we do not believe it would have any adverse impact on populations of marine invertebrates.

Underwater noise during construction activities would be temporary and long-term noise impacts are not expected to be significant. Use of vibratory hammers rather than impact hammers would reduce the noise impact from pile installation. A "noise-alert" procedure may also be used to cause mobile marine species sensitive to the acoustics generated by the pile driving to vacate and avoid the immediate area before pile-driving procedures are continued. Additional potential mitigation measures include time of year restrictions, bubble curtain systems, caissons, or the engagement of a NOAA Fisheries-approved mammal and marine spotter to ensure no sensitive species are within the designated NOAA Fisheries Acoustic Safety Zone during construction activity. Prior to commencing construction activities, Downeast has stated its EI would search the work area for the presence of sea turtles; if a sea turtle were sighted, work would be delayed until the EI provided procedures to the work crew to avoid harassment of the animal.

Downeast has consulted with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss appropriate mitigation measures. Appropriate mitigation measures are also part of the FWS and NOAA Fisheries review of the BA. Mitigation measures would be implemented during all stages of the project, maximizing protection of the listed species by either avoiding adverse impacts, or minimizing the potential for adverse impacts. Downeast has proposed that the following mitigation measures be implemented during all stages of the project, maximizing protection of the listed species by either avoiding adverse acoustic harassment impacts, or minimizing the potential for adverse impacts:

- sound generated by vibratory pile driving would be mitigated by reducing power settings on the hammer, and by enclosing the pile(s) within a confined bubble curtain;
- Downeast would determine the effectiveness of mitigated pile driving by modeling sound levels throughout the ensonified area and provide an updated isopleth map to NOAA Fisheries prior to the issuance of a concurrence letter;
- all pile installation, regardless of technique or equipment would conform to existing thresholds for Level A (i.e., sound pressure level of 180 dB RMS re: 1μPa) for injury to cetaceans, and Level B harassment (160 dB RMS re: 1μPa) for impulse noise and continuous sound (120 dB RMS re: 1μPa) as they pertain to listed marine mammals;
- Downeast would record PEAK sound pressure level and calculate Cumulative Sound Exposure Level (CSEL) and Root Mean Squared (RMS) from the SPL waveform and report results to our staff on a daily basis;
- during rock socket drilling and pile driving, Downeast would monitor sound pressure level (SPL) with hydrophones and a digital recorder capable of operating at a minimum of 30,000 samples per second for a minimum of one second, with an adjustable trigger level, and a range of at least 30 psi. Based on protocol for measuring in-water acoustic fields and natural noise attenuation of 3-6 dB per doubling of distance, a minimum of three locations would be monitored, located approximately 10, 20, and 40 meters from the sound source;
- an acoustic monitoring plan (e.g., locations, personnel, and equipment) would be provided to Max Tritt at the NOAA Fisheries at 17 Godfrey Drive, Suite 1, Orono, Maine 04473 or to max.tritt@noaa.gov at least 30 days prior to implementation;
- if any listed species are encountered in the action area, FERC and NOAA Fisheries Maine Field Station would be contacted immediately at (202) 502-6257 and (207) 866-3756 respectively;
- a post-project report, confirming completion of construction and the successful application of all terms and conditions of the permit, would be submitted to NOAA Fisheries and to FERC within four weeks of project completion; and
- due to the water depth and vessel draft, the use of ship's bow thrusters would be prohibited during low tide when approaching/departing the pier or while docked.

These measures would minimize acoustic harassment impacts on all listed cetatean and sea turtle species. In addition, Downeast has committed to continue its consultation with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss other mitigation measures if appropriate.  Upon completion of ESA consultation and federal and state permitting processes, Downeast would incorporate the final approved construction and mitigation measures into a comprehensive Prevention and Mitigation Manual for use in training of Downeast's construction and operational personnel, which would be filed with FERC for review and approval prior to construction.  Downeast would conduct consultations with federal agencies as FERC's non-federal representative; however, it would be the FERC's responsibility to complete any necessary agency consultations.

<u>Contaminated Sediments</u>

Based upon investigations conducted by Downeast, there are several areas of contaminated sediments located within the footprint of the proposed facilities that could adversely impact surrounding water quality.  However, the mobilization of sediments is not anticipated as being substantially different from normal bottom disruption caused by storm events.  Given the piles used to support the trestle structure (pier, unloading platform, and dolphins) would be vibropiled, no rock or sediment spoil would be generated during pile installation (Balloch 2007).

Despite the aforementioned impacts, the effects associated with construction in Mill Cove are anticipated to be short term and minor.  Given the tidal amplitude and strong currents affecting the area, construction activities are not likely to produce thick layers of sediment in any one location of the project area.  The installation of the pier would also be conducted using a conventional "over-the-top" method of construction whereby the pier trestle is constructed from the shore seaward.  This method of installation would limit the use of barge-mounted equipment reducing the amount of impacts on the Cove seabed from anchoring, as well as reduce the area of habitat disturbance and loss from propeller wash.  Downeast has stated it would use BMPs to minimize/localize turbidity.  In addition, as the pier support structures would be bolted to the bedrock underlying the softer seafloor surface, foundations would not have to be poured or filled, resulting in a relatively small footprint of the seafloor.  Total permanent habitat loss due to piling structures would be approximately 0.11 acre.

Those benthic species that are affected during construction would likely begin recolonizing disturbed habitats within a period of weeks to days after construction for pioneering communities and several years for more "mature" communities.  In addition, mobile fish and larger invertebrates would likely avoid construction activities and return to the area once activities have been completed.

<u>Timing of Construction Activities</u>

To further mitigate for construction-related impacts, Downeast is currently consulting with the appropriate agencies regarding the timing of construction activities to avoid particularly sensitive periods.  Timing may include seasonal considerations to avoid sensitive periods such as during spawning, migration, and peak fishery activity.  Timing may also include avoiding equipment relocation activity during specific periods of the diurnal tide to avoid excessive disturbance to the bottom and reduce sediment resuspension by construction vessels.  Additional mitigation options include specific measures for impact containment, such as the use of silt retention devices to restrict silt plumes.  Downeast has not yet finalized its consultations with the appropriate agencies to establish construction timing restrictions; therefore, **we recommend that:**

- **Downeast should continue to consult with NOAA Fisheries, Maine DMR, and other appropriate agencies to determine any recommended seasonal or construction timing restrictions to minimize impacts on marine species and habitats during all proposed in-water work and pile driving activities at the LNG terminal. Prior to construction of the LNG terminal facilities, Downeast should file with the Secretary copies of its final Prevention and Mitigation Manual, to include correspondence with consulted agencies and a description of any mitigation measures, including seasonal or construction timing restrictions.**

When this information is filed with the Commission, FERC staff will consult with respective agencies as needed during its review.

Invasive Species

Downeast has documented the presence of invasive/exotic marine species, including the common periwinkle and green crab, in the general area surrounding the proposed pier. As is common in the marine environment, adding a vertical structure in the water column may provide additional habitat for all marine species, including invasive/exotic species that may exist in the area. However, it is unlikely that the minimal additional habitat area provided by the pier structures, as compared to the larger habitat area of Mill Cove and Passamaquoddy Bay, would have any discernible effect on either indigenous or invasive/exotic marine species. We have concluded that the proposed pier and construction activities are not likely to exacerbate the current populations of invasive species.

Commercial Fisheries

Impacts on the commercial fisheries would occur both as a result of pier installation, through the alteration of traditional fishing patterns, specifically lobstering and weir operation. The extent of these impacts would depend on the level of fishing activity in the immediate vicinity of the pier. In areas that have been identified as commercial lobster harvesting areas or areas of weir operations that would be disturbed or removed as the result of construction activities, Downeast has agreed to compensate fishermen for any adverse fisheries-related fiscal loss. We have recommended in section 4.8.2.5.1 of this EIS that Downeast complete the necessary consultations to finalize its Fishermen Communication, Coordination and Compensation Plan prior to operation of the LNG terminal.

Communication from the St. Croix Waterway Commission expressed concern for the impact of construction on the commercially important blue mussel and green sea urchin. For the blue mussel, given the generally soft sediments associated with nearly all of the intertidal and subtidal zones within the project area and the strong currents they are subject to, conditions are not generally suitable to support the establishment of large mussel beds that would appeal to commercial harvesters. In addition, as of January 17, 2007, Maine DMR closed the northwest portion of Mill Cove to the harvest of clams, quahogs, oysters, mussels, and other marine mollusks because of pollution. As such, construction of the project would not adversely affect the commercial fishery for blue mussels or commercial harvesting of green sea urchin. The presence of green sea urchins and their associated habitat (kelp beds) are low in the project area and reports from local fishermen indicate that the species is not present in sufficient amounts to be of commercial importance. The project could, however, result in a minor positive net increase in the presence of the species due to the presence of the pier pilings which would provide habitat for mussels and marine vegetation such as kelp and seaweed that are preferred habitats for green sea urchins.

The St. Croix Waterway Commission also expressed concern for impacts on mysid shrimps. These shrimps, while not a commercially important species, are an important food source for marine mammals and groundfish known to occur in the project area, as well as for processing plankton. Mysid shrimp occur in benthic habitats during the day and pelagic habitats during the evening. Construction impacts would include habitat loss and turbidity from the installation of the pilings for the pier, and entrainment during water uptakes for hydrostatic testing. The total area of impact would be minor relative to the available benthic habitat available to these species within the project area. Studies of the mysid shrimp indicate that this species repopulates after disturbance very rapidly (Jumars 2006).

Scoping comments received by the Commission indicated stakeholder concern that the LNG project would disturb or destroy breeding ground for lobster. Data does indicate that the area supports numerous large, egg-bearing females. Habitat within the footprint of the pier would be permanently altered where pilings are installed; however, it is expected that such impact would be minor and that lobsters, being highly mobile, would continue to utilize Mill Cove after construction and throughout operation of the proposed facilities. However, we have recommended that Downeast continue to consult with NOAA Fisheries, Maine DMR, and other appropriate agencies to determine impacts on the local lobster population and any recommended mitigations to minimize impacts on lobster and lobster habitat (see section 4.5.2.2).

Due to the limited nature of recreational fishing activities in the Cove, installation of the Downeast LNG Project would not result in significant adverse impacts.

<u>Impingement and Entrainment</u>

During construction of the LNG terminal, Downeast would conduct hydrostatic testing of the LNG storage tanks using approximately 28 million gallons of water, obtained principally from Passamaquoddy Bay. Entrainment and impingement of fish and other aquatic organisms such as phytoplankton, zooplankton, and ichthyoplankton could occur during water withdrawals. Downeast would minimize entrainment and impingement of fish by regulating the intake rate and by the use of screens on intake hoses. Downeast is currently proposing the use of a #200 mesh filter during intake of hydrostatic test waters. Downeast has also stated it would coordinate with federal and state agency personnel regarding the scheduling of testing to minimize potential conflicts with seasonal/life-cycle periods of important aquatic resources. All water used for testing of the LNG storage tanks would be discharged back to the Bay.

<u>Accidental Releases and Spills</u>

During construction, the potential for spills and accidental releases of material such as diesel fuel, lubricants, and hydraulic fluid could affect fishes and other aquatic life through acute or chronic toxicity, and sub-lethal effects that could affect reproduction, growth, and recruitment. Depending upon the magnitude of the release, it is possible that when combined with the 18+ foot tidal range, some material could wash up onto the intertidal zone, resulting in harm and mortality to intertidal benthos. To minimize the likelihood of accidental spills and releases, Downeast has adopted the measures specified in our Procedures regarding spill prevention and containment near waterbodies. In addition, we have recommended in section 4.3.2.1, that

Downeast develop a Marine SPCC Plan to prevent, respond to, and mitigate any potential spills of oil, gas, lubricants, or other hazardous materials that could occur during construction and operation of the marine terminal. Given the adoption of the measures in our Procedures and the recommendation to develop a Marine SPCC Plan, we believe the risk of accidental spills or the introduction of other hazardous materials to the marine environment and their effects to aquatic life would be effectively minimized.

**Operation Impacts**

Shading

Once completed, the bottom of the pier deck and unloading platform would be approximately 38.1 feet above the surface of the water at MLLW, and would shade a total of approximately 6.6 acres of intertidal, subtidal, and open-water habitat. Included in the area impacted by shading would be about 0.6 acre of eelgrass as mapped by Maine DMR. We have recommended that Downeast conduct project specific mapping to determine potential presence and extent of eelgrass and need for mitigation for potential impacts, including from shading during operation (see section 4.4.2.2). Predatory species, especially those that forage primarily by sight, are often sensitive to intense sunlight and seek shade or deeper water during periods of intense sunlight. Shading of the area underneath the pier could enhance the habitat for predatory species or other species such as lobsters that avoid intense direct sunlight during the day and seek seclusion. The vertical structures associated with the pier structure would also provide additional hard intertidal and subtidal substrate for sessile flora and fauna attachment and could help foster the development of these types of communities.

Lighting

The presence of the pier structure could also affect marine organisms due to shading and the presence of artificial lighting. However, the pier is relatively narrow and would be constructed a sufficient height above the water as to have minor shading affects. The marine transfer area for LNG must have a lighting system and separate emergency lighting that meets Coast Guard standards as published in 33 CFR Part 127.109. Downeast would work with the Coast Guard in coordination with Maine DMR and NOAA Fisheries to establish a lighting plan that would meet 33 CFR Part 127.109 while minimizing the impacts associated with artificial lighting on marine organisms to the extent possible. In addition, while the pier may serve as a detractor to various species due to shading or lighting, the pilings themselves would provide new attachment surfaces for various marine species. In the Eastport region, piers are known for their biological richness.

Propeller Wash

During operation of the LNG terminal, propeller wash and other hydraulic effects from LNG ships and tugs could temporarily increase suspended sediments and turbidity within the pier location. Propeller wash could affect the substrate within and adjacent to the pier location and could scour and dislodge demersal fish eggs and limit the recolonization of benthic species in those areas. However, modeling was conducted for the Boston Harbor Navigation Improvement Project to assess the effect of ship passage on the resuspension of surficial sediments in federal ship channels (COE 1995). The modeling assumed a channel depth of 45 feet and varying vessel drafts from 12 to 42 feet. The study concluded that silt, the predominant grain size of the surficial sediments assessed in the model, can be resuspended by currents as slow as 0.65 feet/second. The study also found that bottom velocities generated by cargo vessels passing at slow speeds through the harbor can exceed this value up to 1,312 feet astern of the vessel and that tugs can generate bottom velocities above this value up to 656 feet astern of the vessel. Turning areas were found to be particularly susceptible to resuspension of sediments as the result of ship passage. The results indicated that the surficial sediments in the federal ship channels and berth areas are subject to resuspension during virtually every ship passage. However, the results also indicated that ship-induced bottom velocities dissipate rapidly following the passage of the ship and that sediments resuspended by these currents settle back to the substrate after being transported relatively short distances (COE 1995).

Following completion of the Boston Harbor Navigation Improvement Project, the COE conducted additional studies to monitor the effect of deep-draft vessel movement on the resuspension of bottom sediments (SAIC 2000, 2001). These studies used static and mobile monitoring techniques to evaluate the impact of the passage of an LNG vessel (Matthew) on bottom sediment resuspension from the confined aquatic disposal cells along a portion of the Mystic River downstream of the Distrigas LNG facility as well as material resuspended from other parts of the channel.

These studies demonstrate that sediment resuspension due to passage of deep-draft vessels can mobilize bottom sediments, but the volume of sediment resuspended is relatively small and the sediments are not transported far from their original locations. Vessel movements within a navigation channel result in short-term water quality effects that generally dissipate within 1 hour of the vessel passing any particular point along the channel.

The potential for resuspended sediment to impact fish eggs and larvae depends upon the species, the concentration of particles, and the duration of exposure. Demersal eggs, such as those of winter flounder, may be dislodged and/or partially or completely covered by fine-grained sediments as they settle back to the bottom. This may slow the exchange of oxygen between the water and egg and, therefore, slow development or cause eggs to experience higher mortality rates (Wilbur and Clarke 2001). Exposure to high levels of suspended solids (between 200 and 500 mg/L) for durations of less than 24 hours has been shown to reduce feeding rates in some fish larvae (Breitburg 1988). In general, however, exposure to increased turbidity for periods of less than one day, which would be likely from LNG vessels, appears to have little measurable effect on pelagic fish eggs and larvae (Kiorboe et al. 1981; Wilbur and Clarke 2001).

Based on the results of the Boston Harbor studies, the increased suspended solids levels resulting from LNG vessel passage could result in reduced feeding rates for some fish larvae in the immediate vicinity of the pier. However, we expect there would be minimal impact on most pelagic fish eggs and larvae because suspended solids concentrations should return to background conditions within one hour or less of ship passage. Additionally, propeller wash due to normal operation of tugs, escort vessels, and LNG vessels would not be expected to increase turbidity in the vicinity of the pier because the sediments in this area appear to be cohesive, soft marine clays. Based on the initial monitoring in the Mystic River, the sediment plume did not rise above mid-water elevations (i.e., the plume was not observed at the water surface, and monitoring equipment indicated a maximum water column elevation of about 20 feet above the channel bottom). The dimensions of the monitored plumes in Boston Harbor suggest that impacts on demersal fish eggs and larvae by remobilized sediments would likely be limited.

Water Withdrawals and Discharges

No seawater would be used in the regasification of the LNG. LNG vessels would require water withdrawals and discharges while at the port for vessel operations. The majority of this water would consist of engine cooling water that is recirculated or cycled through a heat exchanger before being discharged back to Passamaquoddy Bay, and water used for hoteling, ballasting, and fire suppression pump testing. Water circulation and water withdrawals and discharges would result in impacts on marine organisms. It is anticipated that the size of vessels servicing the terminal would range from 125,000 $m^3$ up to 165,000 $m^3$ cargo carrying capacity. To maintain a constant draft while berthed at the pier, LNG vessels would require between 14 million (small capacity 125,000 $m^3$ vessel) and 17 million gallons (large capacity 165,000 $m^3$ vessel, including 165,000 $m^3$ diesel vessel) of seawater ballast. This ballast water would be withdrawn from the surrounding area for a duration of approximately 12 hours per 21-hour cargo unloading period. Vessels would also require between 2.7 million gallons (large capacity 165,000 $m^3$ diesel vessel) and 55.5 million gallons (steam-driven large capacity 165,000 $m^3$ vessel) of water to support engine cooling and between an estimated 2.7 million gallons (large capacity 165,000 $m^3$ diesel vessel) and 7.2 million gallons (125,000 to 165,000 $m^3$ steam-driven vessels) of water to support hoteling needs during the 21-hour cargo unloading period. Diesel powered vessels use a different propulsion system, which requires less water. A breakdown of water intake estimates for the range and type of LNG vessels that are anticipated to service the port are summarized in table 4.5.2.2-4. Ballast, engine cooling, and hoteling water would be drawn through intake openings located on the side of the vessel. These openings would be covered with a strainer plate with slots designed to prevent intake of large objects. Aquatic organisms including zooplankton, icthyoplankton, and mysid shrimp in the immediate vicinity of the LNG vessel could therefore be subject to impingement and/or entrainment during water intake. Ballast, engine cooling, and hoteling intakes on the LNG vessels are located near the bottom of the vessel, and therefore, impingement and/or entrainment would be limited to organisms in the deeper water column (30 to 35 feet below the surface). The impacts on ichthyoplankton, zooplankton, and mysid shrimp related to the water used by vessels servicing the Downeast LNG terminal would vary based on a number of conditions including vessel type, vessel size, and duration at port. Loss estimations of ichthyoplankton and zooplankton from intakes associated with engine cooling and ballasting for each vessel class, species densities (worst case) and 100 percent mortality are included in Appendix O. Hoteling water intakes were not included within the context of this impact assessment; however; intake for this purpose would be relatively minor compared to those associated with engine cooling and ballasting. As indicated in table 4.5.2.2-4, the total zooplankton loss per visit for a full load ballast, based on plankton sampling to date, ranges from a low of 281 million for a diesel 165,000 $m^3$ vessel to a high of 869 million for a steam-driven 165,000 $m^3$ vessel.

The emergency fire suppression system along the pier would also require the use of seawater during periodic system testing with the potential to adversely impact ichthyoplankton and zooplankton in the vicinity of the project area (see table 4.5.2.2-5). The fire system would consist of seven pumps that would draw water from a minimum of 30 feet below the water surface at a capacity of 3,000 gpm per pump. The pumps would be tested weekly and require a total of 180,000 gallons of seawater for a test period of at least one hour per system test. Annual ichthyoplankton and egg losses resulting from the emergency fire suppression testing are estimated to be 44,000 and 134,000, respectively. The total annual zooplankton loss from emergency fire suppression system testing is estimated to be 926 million.

TABLE 4.5.2.2-4

**Vessel Seawater Usage Impacts on Fish Eggs, Fish Larvae, and Zooplankton per Visit Based on Worst Case Densities**

| Vessel class a/ | Cooling flow rate b/ ($m^3$/hr) | Time in port c/ (hrs) | Ballast volume d/ ($m^3$)/(gals) | Total seawater usage/visit e/ ($m^3$)/ (gals) | % of Total area flow f/ (322x106 $m^3$) | % of Total regional flow g/ (1452x106 $m^3$) | Max. Fish eggs h/ (#/$m^3$) | Total fish egg loss/visit i/ | Max. Ichthy. j/ (#/$m^3$) | Total ichthyo loss/visit k/ | Max. Zooplanton l/ (#/$m^3$) | Total zooplankton loss/visit m/ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Full load ballast** | | | | | | | | | | | | |
| 125K MT | 6,341 | 21 | 53,683/ 14,181,548 | 186,835/ 49,356,585 | 0.0580% | 0.0129% | 0.541 | 101,078 | 0.177 | 33,070 | 3733 | 697,455,704 |
| 138K MT | 7,000 | 21 | 53,107/ 14,029,385 | 200,107/ 52,862,677 | 0.0621% | 0.0138% | 0.541 | 108,258 | 0.177 | 35,419 | 3733 | 746,999,431 |
| 145K MT | 7,355 | 21 | 56,964/ 15,048,297 | 211,421/ 55,851,519 | 0.0657% | 0.0146% | 0.541 | 114,379 | 0.177 | 37,421 | 3733 | 789,232,808 |
| 165K MTS | 500 | 21 | 64,759/ 17,107,518 | 232,759/ 61,488,427 | 0.0723% | 0.0160% | 0.541 | 125,923 | 0.177 | 41,198 | 3733 | 868,889,347 |
| 165K MTD | 500 | 21 | 64,759/ 17,107,518 | 75,259/ 19,881,324 | 0.0234% | 0.0052% | 0.541 | 40,715 | 0.177 | 13,321 | 3733 | 280,941,847 |
| **Vessel class a/** | **Cooling flow rate b/ ($m^3$/hr)** | **Time in port c/ (hrs)** | **Ballast volume d/ ($m^3$)** | **Total seawater usage/visit e/ ($m^3$)** | **% of Total area flow f/ (322x106 $m^3$)** | **% of Total regional flow g/ (1452x106 $m^3$)** | **Max. Fish eggs h/ (#/$m^3$)** | **Total fish egg loss/visit i/** | **Max. Ichthy. j/ (#/$m^3$)** | **Total ichthyo loss/visit k/** | **Max. Zooplanton l/ (#/$m^3$)** | **Total zooplankton loss/visit m/** |
| **Light load ballast (80.8% of full load ballast)** | | | | | | | | | | | | |
| 125K MT | 6,341 | 21 | 43,372/ 11,457,670 | 176,524/ 46,632,707 | 0.0548% | 0.0122% | 0.541 | 95,500 | 0.177 | 31,245 | 3733 | 658,964,741 |
| 138K MT | 7,000 | 21 | 42,910/ 11,335,623 | 189,910/ 50,168,914 | 0.0590% | 0.0131% | 0.541 | 102,742 | 0.177 | 33,614 | 3733 | 708,935,732 |
| 145K MT | 7,355 | 21 | 46,027/ 12,159,047 | 200,483/ 52,96,006 | 0.0623% | 0.0138% | 0.541 | 108,462 | 0.177 | 35,486 | 3733 | 748,404,658 |
| 165K MTS | 8,000 | 21 | 52,325/ 13,822,803 | 220,325/ 58,203,717 | 0.0684% | 0.0152% | 0.541 | 119,196 | 0.177 | 38,998 | 3733 | 822,473,225 |
| 165K MTD | 500 | 21 | 52,325/ 13,822,803 | 62,825/ 16,596,609 | 0.0195% | 0.0043% | 0.541 | 33,988 | 0.177 | 11,120 | 3733 | 234,526,740 |

a/ Vessel size class in thousands of metric tons
b/ Flow rate source: John Egan, Marine Master, personal communication 2006
c/ Estimated time in port/at dock: John Egan, Marine Master, personal communication 2006
d/ Ballast volume source: John Egan, Marine Master, personal communication 2006
e/ Total seawater usage per visit = cooling flow rate x time in port + ballast volume
f/ Mean tidal flow across line from St. Andrews, New Brunswick and Lewis Cove, Robbinston, Maine - W.F. Baird & Associates, July 6, 2006, Table 6.1, p. 27
g/ Mean ebb and flood tidal flow in and out of Passamaquoddy Bay through Western Passage - W.F. Baird & Associates, July 6, 2006, Table 6.1, p. 27
h/ Based on maximum October 2006- November 2008 fish egg sampling in Mill Cove (July 2009)
i/ Mill Cove annual maximum total fish egg count multiplied by total visit seawater usage
j/ Based on maximum October 2006- November 2008 ichthyoplankton sampling in Mill Cove( July 2009)
k/ Mill Cove annual maximum ichthyoplankton count multiplied by Total visit seawater usage
l/ Based on maximum October 2006- November 2008 zooplankton sampling in Mill Cove (July 2009)
m/ Mill Cove annual maximum total zooplankton count multiplied by total visit seawater usage

TABLE 4.5.2.2-5

**Fire Suppression Seawater Usage Impacts on Fish Eggs, Fish Larvae, and Zooplankton per Visit Based on Worst Case Densities**

| Number Fire pumps | Pump flow rate (gpm) | Total test flow rate a/ ($m^3$/hr) | Test period (hrs) | Total test volume b/ ($m^3$) | Max. Fish eggs c/ (#/$m^3$) | Total fish egg loss/test d/ | Total fish egg loss/year e/ | Max. Ichthy. f/ (#/$m^3$) | Total ichthy. loss/test g/ | Total ichthy. loss/year h/ | Max. Zooplankton i/ (#/$m^3$) | Total zooplankton loss j/ | Total Annual zooplankton loss k/ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | 3,000 | 4,769 | 1 | 4,769 | 0.214 | **2,580** | **134,164** | 0.134 | **844** | **43,895** | 3733 | **17,803,050** | **925,758,616** |

a/ Total test flow rate ($m^3$/hr) = ((((Pump flow rate (gpm) * 7) * 60min)*3.785 l/gal)/1000 l/$m^3$
b/ Total test volume = Total test flow rate * Test period
c/ Based on maximum October 2006- February 2008 fish egg sampling in Mill Cove (August 2007)
d/ Mill Cove annual worst case total fish egg count multiplied by total test volume
e/ Total fish egg loss/test * 52 tests/year
f/ Based on maximum October 2006- February 2008 ichthyoplankton sampling in Mill Cove (May 2007)
g/ Mill Cove annual worst case total ichthyoplankton count multiplied by total test volume
h/ Total ichthyoplankton loss/test * 52 tests/year
i/ Based on maximum October 2006- February 2008 zooplankton sampling in Mill Cove (August 2007)
j/ Mill Cove annual worst case zooplankton count multiplied by Total test volume
k/ Total zooplankton loss/test * 52 tests/year

The engine cooling water systems of LNG vessels visiting the proposed terminal may include biocides for anti-fouling of engine systems. If biocides are used, the effects to native organisms from discharging cooling waters containing biocides would depend on the type of biocide used. Some biocides could adversely affect aquatic organisms. However, many biocides do not result in toxic reactions with seawater when released, and any chemicals discharged would be rapidly dispersed by the tidal flushing that occurs in Mill Cove. Downeast would have no control over the anti-fouling system used on the visiting LNG vessels.

Impingement and Entrainment

Using the mean annual density of larvae and eggs found over the plankton sampling occasions from October 2006 through February 2008, Downeast estimated the potential annual impacts on fish stocks of individual species resulting from egg and larvae losses. Egg and larvae losses were calculated by employing a worst-case scenario assumption of 61.5 million gallons of seawater usage by an LNG vessel (165,000 $m^3$ steam-driven vessel) per visit, and assumed a total of 68 LNG vessel visits per year.

Equivalent adult losses are based on three assumptions for larvae and egg survival: one adult per 100,000 eggs or larvae, one adult per 10,000 eggs or larvae, and one adult per 1,000 eggs or larvae. The maximum number of equivalent adult losses, based on a survival assumption of one adult fish per 100,000 eggs and one adult fish per 10,000 larvae, are presented for each vessel class in table 4.5.2.2-6. Total annual equivalent adult losses are estimated to range from a low of 12 for a 165,000 $m^3$ diesel vessel to a high of 102 for a 165,000 $m^3$ steam vessel. For commercially important fish species, the total annual equivalent adult losses are estimated to range from a low of 12 for a 165,000 $m^3$ diesel vessel to a high of 36 for a 165,000 $m^3$ steam vessel. Data on equivalent adult losses for specific species can be found in Appendix O.

TABLE 4.5.2.2-6

**Annual Vessel Seawater Usage Adult Equivalency Fish**

| Vessel Class a/ | Total Annual Fish Loss b/ | Total Annual Commercially-Important Fish Loss c/ |
|---|---|---|
| 125K MT | 82 | 29 |
| 138K MT | 87 | 31 |
| 145K MT | 92 | 33 |
| 165K MTS | 102 | 36 |
| 165K MTD | 33 | 12 |

a/ Vessel size class in thousands of metric tons
b/ Total equivalent loss of adult fish assuming a survival rate of 1 fish: 100,000 eggs and 1 fish: 10,000 larvae
c/ Commercially important, NEFMC managed species. Total equivalent loss of adult fish assuming a survival rate of 1 fish: 100,000 eggs and 1 fish: 10,000 larvae
Data presented in Appendix O

The estimated equivalent adult losses in the vicinity of the Downeast LNG Project are within the same order of magnitude, but slightly less, than those previously estimated based on results from the Maine DMR inshore trawl survey sampling within Region 5. Estimated egg and larval losses by species based on Maine DMR trawl survey efforts conducted in October 2001 and June 2002 and 2003 under worst-case scenario are provided in Appendix O.

Despite estimated losses, the significant tidal fluctuations and water exchange that occurs in the project area; the high densities of zooplankton and ichthyoplankton; quick recovery times of mysid shrimp that occur in the surrounding Passamaquoddy Bay; and the comparatively small amount of water withdrawn suggest that the overall impacts on zooplankton, ichthyoplankton, and mysid shrimp in the project area would have inconsequential effects to overall community populations and associated fish stocks. However, NOAA Fisheries staff has expressed concern for plankton losses due to water withdrawals from LNG vessel visits to the Downeast LNG terminal. NOAA Fisheries has recommended monitoring activities to confirm our conclusions. NOAA Fisheries has suggested that such monitoring activities would provide baseline information to assist in adaptive mitigation, should the need arise, for managing potential impacts on these species. NOAA Fisheries has encouraged continued consultation with Downeast to develop a monitoring plan and/or compensatory mitigation program, if necessary, to offset 'life cycle' impacts that may result from the Downeast LNG Project. While we understand NOAA Fisheries' request for ichthyoplankton and zooplankton field survey data during water withdrawals by the LNG carrier, we believe that Downeast's use of best available scientific data for plankton impacts are adequate to determine impacts. Further, we note that Downeast would have no control over the LNG vessels calling on the Project, and would not be able to conduct adaptive management to minimize impacts on the plankton during operation of the vessels.

Thermal Impacts

Thermal impacts associated with vessel engine cooling discharge waters are also expected to be minor and insignificant. CORMIX modeling conducted by Downeast indicates that vessel engine cooling discharges would result in a thermal plume that would dissipate to approximately 1°C or less warmer than ambient conditions at a distance of 15 to 30 meters from the discharge source (see Appendix O). Temperature elevations of 1°C above ambient would not likely have an impact on adult or juvenile marine species or their eggs.

Commercial Fisheries

Impacts on the commercial fisheries would also occur as a result of pier operation, including the fixed safety/security zone around the pier and berthed LNG vessel, through the alteration of traditional fishing patterns, specifically dragging, lobstering, and weir operation. The extent of these impacts would depend on the level of fishing activity in the immediate vicinity of the Downeast LNG pier and the safety/security zones around a vessel at berth. Currently, Downeast is in negotiations with local lobstermen and weir operators known to fish in the vicinity of the pier to establish plans to mitigate and/or compensate for loss of fishing during operations. The Coast Guard's WSR recommends that the size of the fixed safety/security zone for an LNG vessel berthed at the Downeast LNG terminal be a 500-yard radius around the moored vessel. The WSR further recommends that Downeast prepare a Facility Security Plan as required by 33 C.F.R. § 105.120 for review and approval of the COTP Sector Northern New England before the facility begins operations. This plan would provide the conditions and parameters of the safety/security zone at the pier.

Due to the limited nature of recreational fishing activities in the Cove, installation of the Downeast LNG Project would not likely result in significant adverse impacts.

Accidental Releases and Spills

All commercial vessels must comply with MARPOL regulations and the EPA's VGP (for non-recreational vessels, 79 feet or greater in length), which regulates discharges from vessels. Compliance with these applicable regulations would effectively minimize potential impacts on aquatic habitats associated with the discharge of graywater, blackwater, ballast water, or potential accidental releases from LNG vessels at the berth. As discussed in section 4.3.2.1, we have recommended that Downeast develop a Marine SPCC Plan to prevent, respond to, and mitigate any potential spills of oil, gas, lubricants, or other hazardous materials that could occur during construction and operation of the marine terminal. As discussed in section 2.7.1.1, Downeast would have spill containment basins in the process, vaporizer, and LNG transfer areas to collect and contain any LNG spills.

### 4.5.2.3 Sendout Pipeline

The proposed 29.8-mile sendout pipeline would cross a total of 22 fresh waterbodies (see table 4.3.2.2-1). Waterbodies crossed by the proposed LNG project are also discussed in more detail in section 4.3 of this EIS.

Maine's inland freshwater fishery includes a total of 56 freshwater species, 20 of which are classified as sportfish species regularly pursued by anglers. Waterbodies in the project area are generally classified as coldwater fisheries and warmwater fisheries. Of the waterbodies crossed by the proposed sendout pipeline, a total of 13 waterbodies are classified as coldwater fisheries and nine waterbodies are classified as a warmwater fishery. Of these waterbodies, two unnamed streams at MP 2.0 (unnamed stream) and MP 4.3 (unnamed stream, outlet of Keene Lake) were observed to have suitable fish spawning habitat. Species likely to occur in the unnamed stream at MP 2.0 include brown bullhead (*Ameiurus nebulosus*), sunfish (*Lepomis* spp.), and minnows. At the unnamed stream at MP 4.3, species likely to occur include small mouth bass (*Micropterus dolomieu*), brook trout (*Salvelinus fontinalis*), and chain pickerel (*Esox niger*).

The Maine DIFW also noted the potential for brook trout habitat to occur in the vicinity of the crossings of Wapsaconhagen Brook, Eastern Stream, Magurrewock Stream, Anderson Brook, and Wetland 1 at the terminal site. Additionally, the Maine DMR comment letter of February 1, 2008 indicates that the St. Croix River and Magurrewock Stream contain species of concern, including alewife, American eel, and Atlantic salmon. This area is used as a migration corridor for all three species and also may be used by the American eel for rearing purposes. The presence of Atlantic salmon and its habitats in waters crossed by the sendout pipeline are further discussed in section 4.6 of this EIS. Downeast's stream habitat surveys confirmed five stream crossings that are riffle and pool complexes that meet the COE criteria as special aquatic sites. Table 4.5.2.3-1 lists these streams by milepost along with the potential area of disturbance and Downeast's proposed crossing method. Approximately 4,640 square feet of riffle pool habitat would be affected by pipeline construction right-of-way and temporary workspace and approximately 1,740 square feet would be within the permanent right-of-way. Downeast stated it would attempt to avoid installing the pipeline in riffle habitats, where possible.

**Construction Impacts**

Downeast's proposed construction methods for crossing each waterbody are listed in table 4.3.2.2-1. Depending on the construction method used, direct impacts on aquatic habitats and species would either be avoided (e.g., through HDD) or would occur in localized areas. The seasonal construction window for coldwater fisheries is from July 16 to September 30 annually. The seasonal construction window for warmwater fisheries is June 1 to November 30 annually. Downeast proposes to cross streams primarily using dam and pump crossing techniques, except at nine locations where HDD would be used, including an unnamed stream (MP 4.3; outlet of Keene Lake), Flowed Land Ponds (MP 6.7), the tributary of Beaver Brook (MP 8.6; upstream of Flowed Land Ponds, outlet of Carson Heath), the Magurrewock Stream outlet (MPs 14.1 to 14.2), the St. Croix River (MPs 14.3 to 15.3), two unnamed streams (tributaries of the St. Croix River) at MPs 17.8 and 18.1, Anderson Brook (MP 25.2), and the headwater tributary to Anderson Brook at MP 28.9. In addition, Downeast proposes to use the HDD method to cross two streams at MPs 17.8 and 18.1 to avoid affecting riffle pool habitat (see table 4.5.2.3-1). Refer to section 4.3 of this EIS for a detailed description of crossing methods.

TABLE 4.5.2.3-1

**Estimates of Impact on Riffle Pool Habitat**

| **Perennial Stream** | **Milepost** | **Habitat Type** | **Pipeline Installation Method** | **Area Affected (sq. ft.)** | | | |
|---|---|---|---|---|---|---|---|
| | | | | **Workspace – Temporary ROW 25 feet** | **Pipeline Permanent ROW 30 feet** | **Total Construction ROW 55 feet** | **Average Stream Width (feet)** |
| Unnamed Stream (Inlet to Flowed Land Pond) | 7.7 | Low gradient riffle located upstream of ROW | Dam-and-pump | 200.0 | 240.0 | 440.0 | 8.0 |
| Unnamed Stream (Tributary to St. Croix River) | 17.8 | Low gradient riffle | HDD | - | - | - | 3.0 |
| Unnamed Stream (Tributary to St. Croix River) | 18.1 | High gradient riffle | HDD | - | - | - | 1.0 |
| Stoney Brook | 18.4 | Low gradient riffle located in ROW | Dam-and-pump | 325.0 | 390.0 | 715.0 | 13.0 |
| Wapsaconhagen Brook | 21.3 | Low gradient riffle located in ROW | Dam-and-pump | 925.0 | 1,110.0 | 2,035.0 | 37.0 |
| | **Total Area (sq.ft.) (Worst-Case Scenario)** | | | **1,450.0** | **1,740.0** | **3,190.0** | |

General impacts from dam and pump construction techniques would result in in-stream disturbances; however, downstream flow of water would not be interrupted, and the release of sediment to the waterbody would be generally less and of shorter duration than with other methods such as the wet-trench open-cut crossing method.

Although not currently proposed, in the event Downeast's proposed crossing method is determined unsuccessful or infeasible, an open-cut crossing technique may be applied. General impacts from open-cut crossings would occur to aquatic life such as plankton, aquatic vegetation, amphibians, fish, and aquatic invertebrates. Impacts on water quality and associated aquatic habitats would include sedimentation, turbidity, altered water temperatures and dissolved oxygen levels, and introduction of contaminants, all of which can affect the ability of aquatic life to survive and reproduce. Impacts would also include the physical disturbance or destruction of in-stream cover due to trenching and removal of riparian vegetation. Construction activities could also result in blockage of fish migrations and interruptions of spawning activities, as well as entrainment of fishes or reduced stream flows during withdrawals for hydrostatic testing. These potential impacts are discussed below in more detail. To ensure appropriate mitigation measures are employed at any open-cut crossing originally proposed to be crossed by HDD or other dry ditch methods, we recommended in section 4.3.2.2 of this EIS that Downeast file any amended wetland or waterbody crossing plans concurrent with the appropriate state and federal applications for any required permits or approvals to construct the crossing using this plan. The Director of OEP must review and approve the plan in writing before construction of the crossing.

As indicated, pipeline construction would result in sedimentation and turbidity in surface waters and aquatic habitats through clearing and grading of streambanks, in-stream trenching, trench dewatering, and backfilling of the in-stream trench. In addition, blasting could potentially occur in areas of shallow bedrock along the proposed sendout pipeline route (see section 4.1 for details regarding blasting).

Increased sedimentation and turbidity from in-stream construction across waterbodies has the potential to adversely affect fishery resources; however, these types of impacts would be short term and would only occur during the construction phase. Total suspended solid concentrations may increase during construction following in-stream construction, but soon after construction is complete these concentrations would decrease as the in-stream sediments disturbed during construction are allowed to settle.

Turbidity resulting from suspension of sediments during in-stream construction could reduce light penetration and photosynthetic oxygen production. Additionally, re-suspension of organic and inorganic materials can cause an increase in biochemical oxygen demand, resulting in a decrease in dissolved oxygen; however, any decreases in oxygen would be short term and may occur during active construction across waterbodies.

Benthic invertebrates can suffer significant negative effects from deposited sediments because they are adapted to specific substrate particle sizes. As sediment settles into the interstitial spaces in the streambed, the availability of substrate decreases, resulting in decreased species diversity, abundance, and productivity. In turn, fish communities that depend on the benthic invertebrate community as a food source may suffer.

To minimize impacts, all perennial and intermittent streams designated as A, B, coldwater or coldwater/warmwater fisheries would be crossed using dry crossings methods. At crossings where riffle habitat has been identified that would be crossed using a dam and pump or HDD, Downeast has stated it would attempt to avoid installing the pipe in riffle habitats. Where that may not be possible, Downeast would prevent discharge of fill to the streams using construction measures outlined in its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines.* All construction activities would also take place in accordance with requirements set forth by the COE, Maine DEP, and the *Maine Land and Water Quality Bureau's Erosion and Sediment Control Best Management Practices*. To further minimize impacts, Downeast would continue to consult with the appropriate agencies to determine any site-specific timing restrictions for construction.

Construction would require clearing of streamside vegetation, which would result in reduced shading, possible increases in water temperature, and decreased nutrient input from organic debris in some of the streams. In addition, some in-stream and shoreline cover would be altered or lost at the stream crossings and fish that normally reside in these areas would be displaced. However, these effects would be relatively minor because of the small area affected at each stream. The adoption of our Procedures, which limit vegetation maintenance adjacent to waterbodies to allow a riparian strip at least 25 feet wide and to permanently revegetate with native plants across the right-of-way, would reduce the long-term effects of construction. In addition, a riparian buffer extending 100 feet back from the banks of perennial waterbodies (Class A, coldwater, and coldwater/warmwater) would be allowed to grow across the entire width of the project right-of-way following construction, with the exception of a 10-foot-wide strip centered over the pipe. Thus, downstream water temperatures would not be significantly increased.

To ensure impacts are minimized, EIs would be employed to ensure erosion control and all other environmental safeguards are in place and maintained during construction activities. In addition, the FERC would conduct compliance inspections throughout project construction and restoration.

Loss of streambank vegetation could also result in bank erosion if not properly restored. Upon completion of the sendout pipeline, Downeast would restore streambeds and streambanks to approximate pre-construction condition. Streambank stabilization and reseeding following NRCS guidelines would be conducted to restore habitat, shade, and cover to wildlife.

Introduction of pollutants into waterbodies and aquatic habitats could occur through disturbance of contaminated soils or sediments, accidental spills, and inadvertent releases of drilling fluids during HDD operations. Pollutants could affect fishes and other aquatic life through acute or chronic toxicity, and sub-lethal effects that could affect reproduction, growth, and recruitment.

Pollutants can also be introduced during discharge of hydrostatic test waters. However, Downeast has stated that biocides and other potentially toxic hydrostatic test water additives would not be used during hydrostatic testing of the sendout pipeline.

Downeast proposes to cross the unnamed stream (MP 4.3; outlet of Keene Lake), Flowed Land Ponds (MP 6.7), the tributary of Beaver Brook (MP 8.6; upstream of Flowed Land Ponds, outlet of Carson Heath), the Magurrewock Stream outlet (MPs 14.1 to 14.2), the St. Croix River (MPs 14.3 to 15.3), two unnamed streams (tributaries of the St. Croix River) at MPs 17.8 and 18.1, Anderson Brook (MP 25.2), and the headwater tributary to Anderson Brook at MP 28.9 using the HDD method. Downeast also proposes to cross the riffle pool habitat associated with the unnamed steams at MPs 17.8 and 18.1 with a HDD. A pipeline crossing by HDD would avoid stream bottom disruption and subsequent impacts on aquatic habitats along that portion of the pipeline route. However, HDD methods generally require larger workspace areas on either side of the crossing and are not without risk as inadvertent drilling fluid releases could result if the drilling fluid escapes containment at pits or tanks at the HDD entrance and exit points or if a "frac-out" occurs. A frac-out occurs when drilling fluids migrate unpredictably to the surface through fractures, fissures, or other conduits in the underlying rock or unconsolidated sediments. During HDD operations, a frac-out directly into a waterbody would cause turbidity and sedimentation. Potential impacts from increased turbidity would include decreased water quality and compromised aquatic habitat integrity. As suspended materials settle out of the water column, sedimentation would partially or entirely cover the waterbody substrate and any sessile, benthic organisms. Temporary displacement of fish species and their prey items, as well as the potential for the smothering or burying of prey items, and the clogging of fishes' gills could also occur. The proposed HDD drilling fluid, however, would consist of water and bentonite. Bentonite contains a mixture of non-toxic clays and rock particles which if released in small quantities would not be detrimental to fisheries or water quality. However, the release of large quantities into a waterbody could result in adverse impacts on fisheries. To minimize the potential for impacts, Downeast would conduct proactive monitoring of all the drilling operations, including monitoring of drill fluid volumes and pressures and downhole annular pressure between the drill rod and the hole. In addition, Downeast would require the HDD contractor to have the necessary equipment on site (e.g., haybales, pumps, silt booms, vac-trucks) to adequately contain and clean up any fluid lost in the event of a "frac-out" incident. Section 4.3.2.2 describes Downeast's plans for mitigating inadvertent releases of drilling muds.

Normal movements of resident fish and other aquatic organisms would be temporarily interrupted during dam and pump stream crossings. The HDD crossing technique typically does not affect migrating species from ascending or descending stream sections during construction. However, stakeholders have expressed concern that noise and vibrations from an HDD operation could adversely affect fisheries of interest (i.e., Atlantic salmon, alewife, American eel, American shad, rainbow smelt, and blueback herring). Downeast has indicated that HDD crossings would be a minimum of 60 feet below each river and/or streambed; therefore, impacts from HDD vibrations are unlikely. Downeast has also noted that diesel engines used to support HDD operations would contain sound mitigation devices to minimize potential noise impacts. Downeast is also consulting with the Maine DMR to determine if construction activities should be limited during the spawning migration period. The duration of in-stream disturbance also would be short term. Downeast has estimated that each HDD would take between 24 and 48 hours depending on the size of the stream, except for the proposed HDD crossing of the St. Croix River and Magurrewock Stream outlet. Downeast has estimated that the crossings of the St. Croix River and the Magurrewock Stream outlet would take approximately 75 to 90 days to complete, based on the presumption that drilling would be conducted 24 hours per day, with some reduction to 12 hours per day if necessary. For this crossing, Downeast proposes a construction window between June and August to avoid potential impacts on species such as Atlantic salmon, alewife, American eel, American shad, rainbow smelt, and blueback herring. We agree with this proposed construction window. Dam and pump crossings may take longer than other types of crossing (e.g., open-cut), but flow is channeled through a flume or hose for the duration of the crossing, thereby minimizing impacts. Restoration would occur immediately after the crossing further reducing the impact on fisheries and benthic organisms.

Operation of heavy equipment or other vehicles in and near surface waterbodies would also introduce chemical contaminants, such as fuels and lubricants, into surface waters or result in accidental spills during construction. Downeast has adopted the measures specified in our Procedures regarding spill prevention, containment, and minimization near waterbodies. Downeast has also developed a SPCC Plan template to be used by its contractors. These measures and the SPCC Plan template are discussed in more detail in sections 4.3.1.2 and 4.3.1.3 of this EIS, and would include, but not be limited to:

- keeping construction materials, fuels, etc., 100 feet or more from any stream or wetland system, except under limited, highly controlled circumstances;

- refueling construction equipment in upland areas 100 feet or more from any stream or wetland system, except under limited, highly controlled circumstances; and
- not washing construction equipment in/or immediately adjacent to any wetland or watercourse.

Given the adoption of the measures in our Procedures and the measures included in Downeast's SPCC Plan template, the risk of accidental spills or the introduction of other hazardous materials to waterbodies and their effects to aquatic life would be effectively minimized.

Hydrostatic testing of the sendout pipeline would be conducted using approximately 6.1 million gallons of freshwater withdrawn from the BUD through a direct connection to the fire hydrant system (see section 4.3.2.2 of this EIS). Therefore, entrainment of fish and other aquatic organisms would not occur during withdrawals of water for hydrostatic testing of the pipeline facilities.

Downeast would prevent or adequately limit impacts from hydrostatic testing by implementing its Procedures. In addition, the sendout pipeline may be hydrostatically tested in segments, allowing the re-use of the same water for different segments. No chemicals would be added to the test water and waters would be discharged back to surface waterbodies through a straw bale dewatering structure adjacent to an unnamed creek at MP 17.5 or the BUD sewer system, if feasible. The rate of flow and discharge location would be controlled to prevent temporary flooding conditions. The estimated discharge flow rate is 1,400 to 2,800 gpm. Discharges would also comply with regulatory permit conditions and would be controlled to prevent scour and sedimentation, flooding, and the introduction of foreign or toxic substances into the aquatic system.

Due to the limited and short-term nature of stream crossings during construction of the sendout pipeline, installation would not likely result in significant adverse impacts. In addition, given the adoption of the measures in our Procedures and the measures included in Downeast's SPCC Plan, construction windows to avoid spawning fish, use of HDD construction methods, avoiding habitat such as riffle pools, and other mitigations and best practices being employed, we conclude that impacts on waterbodies and their effects to aquatic life would be effectively minimized.

### Operation Impacts

Operation of the sendout pipeline would not have a permanent impact on fishery resources. The pipeline would be buried below the bed of waterbodies, and the bed and banks of the streams would be stabilized and restored. If maintenance activities were required, Downeast would employ protective measures substantially the same as those used during construction. As a result, any impacts derived from maintenance would be short term in nature and similar to those discussed above for the initial pipeline construction. The minor clearing of riparian vegetation in localized areas would not be expected to cause significant temperature increases downstream. As stated above, Downeast would allow a riparian buffer at least 25 feet wide to permanently revegetate with native plant species across the right-of-way after construction is complete.

### 4.5.3 Essential Fish Habitat

The MSA (Public Law 94-265 as amended through October 11, 1996) was established, along with other goals, to promote the protection of EFH in the review of projects conducted under federal permits, licenses, or other authorities that affect or have the potential to affect such habitat. EFH is defined in the act as those waters and substrate necessary to fish for spawning, breeding, feeding, or growth to maturity.

Federal agencies that authorize, fund, or undertake activities that may adversely impact EFH must consult with NOAA Fisheries. Although absolute criteria have not been established for conducting EFH consultations, NOAA Fisheries recommends consolidated EFH consultations with interagency coordination procedures required by other statutes, such as the NEPA, Fish and Wildlife Coordination Act, ESA, or the Federal Power Act (50 CFR 600.920(e)) in order to reduce duplication and improve efficiency. Generally, the EFH consultation process includes the following steps:

1) **Notification –** The action agency should clearly state the process being used for EFH consultations (e.g., incorporating EFH consultation into EIS, Section 10 permit, etc.).

2) **EFH Assessment –** The action agency should prepare an EFH Assessment that includes both identification of affected EFH and an assessment of impacts. Specifically, the EFH should include: (1) a description of the proposed action; (2) an analysis of the effects (including cumulative effects) of the proposed action on EFH, the managed fish species and major prey species; (3) the federal agency's views regarding the effects of the action on EFH; and (4) proposed mitigation, if applicable.

3) **EFH Conservation Recommendations –** After reviewing the EFH Assessment, NOAA Fisheries would provide recommendations to the action agency regarding measures that can be taken by that agency to conserve EFH.

4) **Agency Response –** Within 30 days of receiving the NOAA Fisheries recommendations, the action agency must respond to NOAA Fisheries. The action agency may notify NOAA Fisheries that a full response to the conservation recommendations will be provided by a specified completion date agreeable to all parties. The response must include a description of measures proposed by the agency for avoiding, mitigating, or offsetting the impact of the activity on EFH.

In 2009, the FERC staff consolidated EFH consultations for the Downeast LNG Project with the interagency coordination procedures required under NEPA and ESA. On May 19 of that year, the FERC contacted NOAA Fisheries for the purposes of reviewing this project under NEPA. NOAA Fisheries provided recommendations to the FERC on June 25, 2009 regarding mitigation and EFH conservation for the project. NOAA Fisheries indicated that construction and operation of the proposed Downeast LNG Project would result in adverse effects to fishery resources and habitats. NOAA Fisheries recommended that seasonal work restrictions be developed in consultation with federal and state resource agencies, that measures be taken to reduce intake velocity to minimize egg and larval entrainment, and that site-specific HDD plans be developed. In addition, NOAA Fisheries recommend that a biological monitoring plan be presented and that a compensatory mitigation be provided to offset temporary and permanent impacts on fishery resources and habitats.

An assessment of potential effects of the project on EFH, incorporating NOAA Fisheries comments on the draft EIS has been included in Appendix G. The EFH Assessment includes a detailed description of the life history characteristics and habitat preferences of EFH species and a discussion of the potential for these species to occur within the proposed project's area of potential effect. A summary of the EFH assessment is included in the following sections.

#### 4.5.3.1 Waterway for LNG Marine Traffic and LNG Terminal

To delineate EFH, coastal waters were mapped by regional Fisheries Management Councils (FMCs) and superimposed with 10-minute by 10-minute square coordinate grids or quadrants. The proposed project's terminal area crosses three of the 10-minute by 10-minute quadrants that have been designated EFH for 29 species of finfish, three species of shellfish, and four species of skate. However, based on the review of available literature, we believe that the project would have no impact on 22 of these species because the project would not be within the known range of the species, the project would not impact habitat for the species, or EFH has not been designated for the species in question (see table 4.5.3.1-1). These 22 species are not addressed further in this assessment.

TABLE 4.5.3.1-1

**Essential Fish Habitat Designated by NEFMC for Species Identified as Occurring in the Waters of Passamaquoddy Bay, Maine, Eliminated from Further Consideration for the Downeast LNG Project**

| Species | Reason for Elimination from Further Consideration | Determination of Effect |
|---|---|---|
| Barndoor skate (*Dipturus laevis*) | EFH not designated for this species within the project area | No Effect |
| Black sea bass *(Centropristus striata)* | Relative abundance is rare within the project area | No Effect |
| Bluefish *(Pomatomus saltatrix)* | Relative abundance is rare within the project area | No Effect |
| Butterfish *(Peprilus triacanthus*); also called Atlantic butterfish | Relative abundance is rare within the project area | No Effect |
| Haddock *(Melanogrammus aeglefinus)* | Relative abundance is rare within the project area | No Effect |
| Little skate (*Leucoraja erinacea*) | EFH not designated for this species within the project area | No Effect |
| Long finned squid *(Loligo pealei)* | Relative abundance is rare within the project area | No Effect |
| Monkfish *(Lophius americanus)* | Relative abundance is rare within the project area | No Effect |
| Ocean quahog *(Artica islandica)* | Relative abundance is rare within the project area | No Effect |
| Offshore hake *(Merluccius albidus)* | Relative abundance is rare within the project area | No Effect |
| Redfish *(Sebastes fasciatus)* | Relative abundance is rare within the project area | No Effect |
| Scup *(Stenotomus chrysops)* | Relative abundance is rare within the project area | No Effect |
| Short finned squid *(Illex illecebrosus)* | Relative abundance is rare within the project area | No Effect |
| Smooth skate (*Malacoraia senta*) | EFH not designated for this species within the project area | No Effect |
| Spiny dogfish *(Squalus acanthias)* | Relative abundance is rare within the project area | No Effect |
| Summer flounder *(Paralicthys dentatus)* | Relative abundance is rare within the project area | No Effect |
| Surf clam *(Spisula solidissima)* | Relative abundance is rare within the project area | No Effect |
| Thorny skate (*Amblyraja radiata*) | EFH not designated for this species within the project area | No Effect |
| Tilefish *(Lopholatilus chamaeleonticeps)* | Relative abundance is rare within the project area | No Effect |
| Winter skate (*Leucoraja ocellata)* | EFH not designated for this species within the project area | No Effect |

| TABLE 4.5.3.1-1<br>**Essential Fish Habitat Designated by NEFMC for Species Identified as Occurring in the Waters of Passamaquoddy Bay, Maine, Eliminated from Further Consideration for the Downeast LNG Project** | | |
|---|---|---|
| **Species** | **Reason for Elimination from Further Consideration** | **Determination of Effect** |
| Witch flounder *(Glyptocephalus cynoglossus)* | Relative abundance is rare within the project area | No Effect |
| Yellowtail flounder *(Pleuronectes ferruginea)* | Relative abundance is rare within the project area | No Effect |
| Sources: Jury et al.1994, David K. Stevenson, Ph.D (personal communication) | | |

The remaining 14 species, and their associated life history stages, with designated EFH that are identified as occurring or having the potential of occurring within the project area are listed in table 4.5.3.1-2. A detailed description of the life history characteristics and habitat preferences of EFH species is provided in the EFH Assessment included as Appendix G, as is a discussion of the potential for these species to occur within the proposed project's terminal area of potential effect.

In general, many of the impacts on benthos described in section 4.5.2.1 and section 4.5.2.2 are also relevant in many instances as a component of impacts on EFH. Seafloor disturbances would have both temporary and permanent impacts on demersal species such as loss of eggs, temporary reduction in benthic prey items, or loss of habitat from the pilings associated with the pier. Construction of the pier and shading during operation would have some impact on eelgrass recently identified by Maine DMR mapping. The pier would cross about 350 feet of mapped eelgrass and impact an estimated 0.6 acre from shading during operation. We have recommended that Downeast conduct project specific mapping and determine potential presence and extent of eelgrass and need for mitigation for these impacts (see section 4.4.2.2).

Entrainment of eggs and larvae would occur with water withdrawals for LNG vessel ballast, hoteling, fire suppression, and engine cooling needs, as well as weekly fire suppression system testing and the one-time hydrostatic test water withdrawals associated with the testing of the LNG storage tanks. However, we believe that the significant tidal fluctuations and water exchange that occurs in the project area; the high densities of zooplankton and ichthyoplankton; and the comparatively small amount of water withdrawn suggest that the overall impacts on zooplankton, ichthyoplankton, and mysid shrimp in the project area would have inconsequential effects to overall community populations and associated fish stocks. NOAA Fisheries has recommended that Downeast conduct monitoring to confirm our conclusions. While we understand NOAA Fisheries' request for ichthyoplankton and zooplankton field survey data during water withdrawals by the LNG carrier, we believe that Downeast's use of best available scientific data for plankton impacts are adequate to determine impacts. Further, we note that Downeast would have no control over the LNG vessels calling on the Project, and would not be able to conduct adaptive management to minimize impacts on the plankton during operation of the vessels. Any new navigation safety upgrades or enhancements, such as data buoys and aids to navigation, installed in the waterway would have no effect to EFH.

Impacts on EFH from pier construction across Mill Cove would primarily be temporary, and the acreage affected for construction of the pier is small. The pier is relatively narrow and would be of sufficient height above the water as to have minimal shading affects. The pilings would create structures that could benefit some species and may interfere with other species' use of the area. Operation of the LNG terminal and the associated increase in vessel traffic in the waters of the proposed transit route would result in increased levels of noise, water use, and nighttime lighting at the pier, which could alter conditions and affect species residing in or moving through these areas.

### 4.5.3.2 Sendout Pipeline

The proposed route for the project's sendout pipeline crosses a portion of the St. Croix River longitudinally. NOAA Fisheries has designated the St. Croix River as EFH and as a Habitat Area of Particular Concern for Atlantic salmon. EFH for Atlantic salmon is described as all waters currently or historically accessible to Atlantic salmon within the streams, rivers, lakes, ponds, wetlands, and other waterbodies of Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. In general, impacts on the benthos as described in sections 4.5.2.1 and 4.5.2.2 would be avoided since the longitudinal crossing of the St. Croix River and the crossing of the head of Magurrewock Stream would be done using HDD, as described in detail in section 4.5.2.3. Entrainment of eggs and larvae would not occur as a result of hydrostatic test water withdrawals associated with the testing of the sendout pipeline system, because the water would be obtained from the BUD through a direct connection to the fire hydrant system not directly from the St. Croix River or Magurrewock Stream. Downeast would require make-up water for mixing of the HDD drilling mud, but has not yet identified a source. Impacts on EFH associated with the operation of the sendout pipeline are not anticipated.

TABLE 4.5.3.1-2

**Essential Fish Habitat Designated by NEFMC for Species Identified as Occurring or Having the Potential of Occurring, With Relative Abundance Estimates for Saltwater Salinity Zones, Within the Project Area in the Waters of Passamaquoddy Bay, Maine**

| Species | Eggs | Larvae | Juveniles | Adults | Spawning Adults |
|---|---|---|---|---|---|
| American plaice *(Hippoglossoides platessoides)* | C | C | C | C | C |
| Atlantic cod *(Gadus morhua)* | | C | C | C | |
| Atlantic halibut *(Hippoglossus hippoglossus)* | ND | ND | ND | ND | ND |
| Atlantic herring *(Clupea harengus* | | A | H | H | |
| Atlantic mackerel *(Scomber scombrus)* | | | C | C | |
| Atlantic salmon *(Salmo salar)* | | | C | C | |
| Atlantic sea scallop *(Placopecten magellanicus)* | A | A | A | A | A |
| Ocean pout *(Macrozoarces americanus)* | A | A | A | A | A |
| Pollock *(Pollachius virens)* | | C | A | C | |
| Red hake *(Urophycis chuss)* | | | C | C | |
| White hake *(Urophycis tenuis)* | | | A | A | |
| Whiting *(Merluccius bilinearis)* also called Silver hake | | | A | A | |
| Windowpane flounder *(Scopthalmus aquosus)* | C | C | C | C | C |
| Winter flounder *(Pleuronectes americanus)* | H | H | H | H | H |

Sources: NEFMC 1998a; Jury et al. 1994
**Key**:
A indicates that EFH has been designated within the square for a given species and life stage with abundant relative abundance.
C indicates that EFH has been designated within the square for a given species and life stage with common relative abundance.
H indicates that EFH has been designated within the square for a given species and life stage with highly abundant relative abundance.
ND indicates no relative abundance data reported, but life history stage is known to occur.
Blank cells indicate that the particular life history stage is not known to occur based on Jury et al. 1994.

## 4.6 THREATENED, ENDANGERED, AND OTHER SPECIAL STATUS SPECIES

Federal agencies are required by Section 7 of the ESA (Title 16 USC Part 1536(c)), as amended (1978, 1979, and 1982), to ensure that any actions authorized, funded, or carried out by the agency do not jeopardize the continued existence of a federally listed endangered or threatened species, or result in the destruction or adverse modification of the designated critical habitat of a federally listed species. Federal action agencies (e.g., the FERC and the COE) are required to consult with the FWS and/or NOAA Fisheries to determine whether federally listed endangered or threatened species or designated critical habitat are found in the vicinity of the proposed project, and to determine the proposed action's potential effects to those species or critical habitats. For actions involving major construction activities with the potential to affect listed species for designated critical habitat, the federal agency must prepare a BA. The action agency must submit its BA to the FWS and/or NOAA Fisheries, and if it is determined that the action may adversely affect a listed species, the federal agency must submit a request for formal consultation to comply with Section 7 of the ESA. In response, the FWS or NOAA Fisheries would issue a Biological Opinion as to whether or not federal action would likely jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat.

As the lead federal agency conducting the NEPA analysis, FERC is also analyzing project-related activities authorized by the COE that could potentially affect federally listed endangered and threatened species. In compliance with Section 7 of the ESA, the FERC staff prepared a BA that was included with the draft EIS, and a revised BA submitted to the FWS and NOAA Fisheries in June 2012. The revised BA is included in Appendix C of this EIS. The BA details the environmental baseline for federally listed species and critical habitat; direct, indirect, interdependent and interrelated, and cumulative effects; proposed conservation measures; and determinations of effect. To ensure compliance with the ESA, including changes to ESA listed species that could occur prior to the start of construction, **we recommend that:**

**Downeast <u>should not begin construction until</u>:**

- **a. the FERC staff completes Endangered Species Act consultation with the FWS/NOAA Fisheries; and**
- **b. Downeast has received written notification from the Director of OEP that construction or use of mitigation may begin.**

A general summary of the information included in the BA is included below, along with a detailed assessment of project impacts on state-listed and other special status species. For purposes of this environmental analysis, special status species of animals and plants include species that are listed by the federal government as endangered, threatened, or candidate species; species that are listed by Maine as endangered, threatened, or species of concern; and species identified by federal or state agencies as rare or sensitive with the potential to occur in the vicinity of the proposed project.

In addition to protection by the ESA, some species are protected by other legislation. The MMPA prohibits, with certain exceptions, the take of marine mammals in waters of the United States. Six species of federally listed marine mammals have been recorded within the proposed Downeast LNG Project area, including North Atlantic right, fin, humpback, sei, blue, and sperm whales, while another five species of marine mammals under the protection of the MMPA are likely to occur in the project area. The MBTA implements various treaties and conventions for the protection of migratory birds. Under this act, taking, killing, or possessing migratory birds is unlawful. Species protected by the MBTA include the bald eagle and upland sandpiper, and various other species that do not receive other federal or state protection. The Bald and Golden Eagle Protection Act (1940; amended 1962) prohibits sale or trade of these eagle species.

In June 2003, Canada enacted the SARA to prevent Canadian indigenous species, subspecies, and distinct populations from becoming extirpated or extinct; to provide for the recovery of endangered or threatened species; and to encourage the management of other species to prevent them from becoming at risk. SARA prohibits killing, harming, harassing, capturing, or taking listed species, and destroying their habitats. Regulatory agencies overseeing jurisdictional enforcement include Environment Canada, Parks Canada, and Fisheries and Oceans Canada. Under SARA, the leatherback sea turtle, Atlantic salmon (inner Bay of Fundy population), North Atlantic right whale, blue whale (Atlantic population), and northern bottlenose whale are listed as endangered and the fin whale, harbor porpoise, and Atlantic wolffish are listed as species of special concern. Note that the northern bottlenose whale and harbor porpoise are addressed in section 4.5.2.

Downeast initiated informal consultations with the Maine DIFW, FWS, NOAA Fisheries, and Maine NAP (a grant-funded program within the Maine Department of Conservation). Results of these consultations identified 46 federal and/or state special status species that could potentially occur in the project area. The FERC initiated formal consultation with the FWS and NOAA Fisheries on May 19, 2009. This EIS section also evaluates federally designated critical habitat for three ESA-listed species.

Based on review of available literature and the results of field surveys conducted by Downeast, we believe that the project would have no effect to 34 of these species because the project would not be within the known range of the species or because the project would not impact habitat for the species (table 4.6-1). Additionally, federally designated critical habitat for three species (Atlantic salmon, leatherback sea turtle, and right whale) does not overlap any feature of the proposed project. These 34 species and federally designated critical habitats are not addressed further in this EIS. The remaining 12 species are listed in table 4.6-2 and discussed below.

TABLE 4.6-1

**Federally and State-Listed Endangered and Threatened Species or Critical Habitats Eliminated From Further Consideration for the Downeast LNG Project**

| Species | Status a/ | Reason for Elimination from Further Consideration b/ | Determination of Effect |
|---|---|---|---|
| **Fish** | | | |
| Critical Habitat of the Atlantic salmon (Salmo salar) | - | The sendout pipeline would not cross any waterbodies designated as critical habitat | No effect |
| **Reptiles** | | | |
| Loggerhead Sea Turtle *(Caretta caretta)* | F-T | Project area occurs north of typical range; extremely rare occurrence within Gulf of Maine. | No effect |
| Atlantic Ridley Sea Turtle (*Lepidochelys kempii*) | F-T | Project area is beyond known habitat range for the species. | No effect |
| Critical Habitat of the Leatherback Sea Turtle | - | Vessels carrying LNG to the Downeast LNG terminal are unlikely to transit near coastal waters adjacent to Sandy Point, St. Croix, | No effect |

TABLE 4.6-1

**Federally and State-Listed Endangered and Threatened Species or Critical Habitats Eliminated From Further Consideration for the Downeast LNG Project**

| Species | Status a/ | Reason for Elimination from Further Consideration b/ | Determination of Effect |
|---|---|---|---|
| (*Dermchelys coriacea*) | | U.S. Virgin Islands. | |
| Blandings Turtle (*Emydoidea blandingii*) | ME-E | Suitable habitat not present in project area. | No effect |
| Spotted Turtle (*Clemmys guttata*) | ME-T | Suitable habitat not present in project area. | No effect |
| **Mammals** | | | |
| Canada lynx (*Lynx* Canadensis) | F-T | Suitable habitat not present in project area. | No effect |
| Critical Habitat of the North Atlantic right whale (*Eubalaena glacialis)* | - | Marine traffic route and LNG terminal would not directly impact designated critical habitat for this species | No effect |
| New England Cottontail (*Sylvilagus* transitionalis) | C | Suitable habitat not present in project area. | No effect |
| **Birds** | | | |
| Least Tern (*Sterna antillarum*) | ME-E | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| Razorbill (*Alca torda*) | ME-T | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| Atlantic Puffin (*Fratercula Circticca*) | ME-T | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| Harlequin Duck (*Histrionicus histrionicus*) | ME-T | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| Arctic Tern (*Sterna paradisaea*) | ME-T | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| Golden Eagle (*Aquila chrysaetos*) | ME-E | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| American Pipit (*Anthus rubescens*) | ME-E | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| American Pipit (*Anthus rubescens*) | ME-E | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| Piping plover (*Charadrius melodus*) | F-T | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| Roseate tern (*Sterna dougallii dougallii*) | F-E | Marine traffic route and LNG terminal would not directly impact the nearshore habitats associated with this species. | No effect |
| Upland Sandpiper (*Bartramia longicauda*) | ME-T | Suitable habitat not present in project area. | No effect. |
| **Plants** | | | |
| Prairie White-fringed Orchid (*Platanthera llecuophaea*) | F-T | Suitable habitat not present in project area. | No effect |
| Furbish's Lousewort (*Pedicularis furbishiae*) | F-T | Suitable habitat not present in project area. | No effect |
| Sparse-flowered Sedge (*Carex tenuiflora*) | ME-SC | Suitable habitat not present in project area. | No effect |
| Bog Bedstraw (*Galium labradoricum*) | ME-SC | Suitable habitat not present in project area. | No effect |
| Small whorled pogonia (*Isotria medeoloides*) | F-T | Suitable habitat not present in project area. | No effect |
| White Wood Aster (*Aster divaricatus*) | ME-T | Suitable habitat not present in project area. | No effect |
| Swamp White Oak (*Quercus bicolor*) | ME-T | Suitable habitat not present in project area. | No effect |

TABLE 4.6-1

**Federally and State-Listed Endangered and Threatened Species or Critical Habitats Eliminated From Further Consideration for the Downeast LNG Project**

| Species | Status a/ | Reason for Elimination from Further Consideration b/ | Determination of Effect |
|---|---|---|---|
| Scarlet Oak (*Quercus coccinea*) | ME-E | Suitable habitat not present in project area. | No effect |
| Dryland Sedge (*Carex siccata*) | ME-SC | Suitable habitat not present in project area. | No effect |
| Broad Beech Fern (*Phegopteris hexagonoptera*) | ME-SC | Suitable habitat not present in project area. | No effect |
| Awned Sedge (*Cyperus squarrosus)* | ME-SC; Ex? | Suitable habitat not present in project area. | No effect |
| Showy Lady's-Slipper (*Cypripedium reginae*) | ME-T | Suitable habitat not present in project area. | No effect |
| Swamp Fly-Honeysuckle (*Lonicera oblongifolia*) | ME-SC | Suitable habitat not present in project area. | No effect |
| **Invertebrates** | | | |
| Ebony Boghaunter (*Williamsonia fletcheri*) | ME-SC | Species is to be delisted in the state of Maine. | No effect |
| Juniper Hairstreak Butterfly (*Callophrys gryneus*) | ME-E | Suitable habitat not present in project area. | No effect |
| Brook Floater (*Alasmidonta varicose*) | ME-T | Suitable habitat not present in project area. | No effect |
| Creeper (*Strophitus undulatus)* | ME-SC | Suitable habitat not present in project area. | No effect |

a/ Status: F = Federal, ME = Maine, E = Endangered, T = Threatened, SC = Species of Concern, C=Candidate, Ex?=Possibly Extirpated.
b/ Downeast conducted habitat surveys during 2006.

### 4.6.1 Current Status of Species

This section describes the federally and state-threatened, endangered, and candidate species that have the potential to occur within or adjacent to the proposed project. Note that the BA provides detailed discussions of federally threatened and endangered species; whereas ESA candidate and state-listed species are only discussed in this EIS.

TABLE 4.6-2

**Federally and State-Listed Wildlife and Plant Species and Designated Critical Habitats that Potentially Occur Near the Downeast LNG Project**

| Species | Habitat near the Project | Facilities with Potential to Affect Species | Federal Status a/ | State Status a/ | Determination of Effects b/ |
|---|---|---|---|---|---|
| **Fishes** | | | | | |
| Atlantic Salmon (*Salmo salar*) | Dennys River (ME) and other streams within the Gulf of Maine DPS Geographic Range | Waterway; LNG Terminal; Sendout Pipeline | E | - | NLAA |
| Atlantic Wolffish (*Anarhichas lupus)* | Rocky outcroppings or seaweed beds in Georges Bank and western Gulf of Maine | Waterway | C | - | NLAA |
| Shortnose Sturgeon (*Acipenser brevirostrum*) | Coastal bays, estuaries, and rivers | Waterway; LNG Terminal | E | - | NLAA |

TABLE 4.6-2

**Federally and State-Listed Wildlife and Plant Species and Designated Critical Habitats that Potentially Occur Near the Downeast LNG Project**

| Species | Habitat near the Project | Facilities with Potential to Affect Species | Federal Status a/ | State Status a/ | Determination of Effects b/ |
|---|---|---|---|---|---|
| Atlantic Sturgeon (*Acipenser oxyrinchus*) | Coastal bays, estuaries, and rivers | Waterway; LNG Terminal | T | - | NLAA |
| **Mammals** | | | | | |
| North Atlantic Right Whale *(Eubalaena glacialis)* | Coastal | Waterway; | E | - | NLAA |
| Fin Whale *(Balaenoptera physalus)* | Coastal | Waterway; | E | - | NLAA |
| Humpback Whale *(Megaptera novaeangliae)* | Coastal | Waterway; | E | - | NLAA |
| Sei Whale *(Balaenoptera borealis)* | Coastal | Waterway; | E | - | NLAA |
| Blue Whale (*Balaenoptera musculus)* | Offshore | Waterway; | E | - | NLAA |
| Sperm Whale *(Physeter macrocephalus)* | Offshore | Waterway | E | - | NLAA |
| **Reptiles** | | | | | |
| Leatherback Sea Turtle (*Dermchelys coriacea*) | Marine – offshore | Waterway; LNG Terminal | E | - | NLAA |
| **Birds** | | | | | |
| Bald Eagle (*Haliaeetus leucocephalus*) | Coastal habitat and open waterbodies | Waterway; LNG Terminal; Sendout Pipeline | - | T | N/A |

a/ Candidate (C); Endangered (E); Threatened (T), Special Concern Species (SC),; no listing ( - )
b/ May Affect, Not Likely to Adversely Affect (NLAA); Likely to Adversely Affect (LAA); No Effect (NE) and Not Applicable (N/A).
c/ Critical habitat for the leatherback sea turtle is described in table 4.6-1.

### 4.6.1.1 Federally Listed Threatened and Endangered Species

#### Fish

Atlantic Salmon

In the United States, the Gulf of Maine DPS of Atlantic salmon was federally listed as endangered in eight Maine rivers in November 2000 (65 FR 69459). In September 2008, the Services determined that naturally spawned and conservation hatchery populations of Atlantic salmon whose freshwater range occurs in the watersheds from the Androscoggin River northward along the Maine coast to the Dennys River, constitutes a new Gulf of Maine DPS and hence a ‘‘species’’ for listing as endangered under the ESA. Effectively, this added populations of Atlantic salmon from the Saco, Kennebec, and Penobscot Rivers to the eight rivers previously listed by the Services in 2000 (50 CFR Parts 17 and 224). In June 2009, the Services expanded the Maine DPS to officially include populations existing in the Androscoggin, Kennebec, and Penobscot River basins (74 FR 29344). Additionally, the Atlantic salmon Inner Bay of Fundy population is listed by Canada's SARA as endangered.

On June 19, 2009, the entire occupied range of the Gulf of Maine DPS was designated as critical habitat in 45 specific areas occupied by Atlantic salmon, comprising 19,571 kilometers of perennial river, stream, and estuary habitat, and 799 square kilometers of lake habitat. These areas are part of three salmon habitat recovery units, including the Penobscot Bay, Merrymeeting Bay, and Downeast Coastal regions (74 FR 29300). On June 19, 2009, the Services revised the Gulf of Maine DPS to include naturally spawning and conservation hatchery populations of anadromous Atlantic salmon whose freshwater range occurs in the watersheds from the Androscoggin River northward along the Maine coast to the Dennys River (74 FR 29300 29341). The DPS also includes wherever listed salmon occur in the marine and estuarine environment. Many factors contributed to the listing of Atlantic salmon in the Gulf of Maine DPS, including (but not limited to) critically low numbers of adult returns, low marine survival rates, altered water quality of freshwater habitat, and disease, among others. In 2005, the *Final Recovery Plan for the Gulf of Maine Distinct Population Segment of Atlantic Salmon* (NOAA Fisheries and FWS 2005a) was completed. A new status review for the Gulf of Maine DPS was published in July 2006.

Adult Atlantic salmon live at sea, but return to their natal freshwater streams to spawn. Spawning typically occurs during mid-October to mid-November. Typical stream spawning areas consist of gravelly substrates within riffle habitat. Eggs develop through the winter and hatch as larvae in spring. Newly hatched salmon remain in or near the nest until the parr stage (when vertical bars develop along the sides). Habitat used by parr is typically riffle areas characterized by adequate cover (gravel and rubble up to 20 cm), moderate water depth (10 to 60 cm) and moderate to fast water flow (30 to 90 cm/sec). Parr remain in freshwater from two to six years, and begin the physiological transformation that prepares them for marine habitats when they reach 12 to 24 cm in length. The time at which parr move downstream toward the sea varies from late spring to fall, but in Gulf of Maine streams this usually occurs in June and July (Baum 1997). In general, salmon prefer cool water temperatures; water temperatures greater than 82°F (28°C) is considered harmful, and greater than 75°F (24°C) is thought to inhibit growth and contribute to overwinter mortality. The marine stage of the Atlantic salmon life cycle is the least understood; however, salmon will spend one to three years at sea before returning to spawn in the natal streams. The occurrence of documented Atlantic salmon habitats is shown in Appendix F, figure F-35.

<u>Atlantic Wolffish</u>

The Atlantic wolffish is listed as a species of concern and is undergoing a status review, as a candidate species, to determine if ESA listing is warranted; it is listed as a species of special concern under Canada's SARA. The Atlantic wolffish are distributed in the North Atlantic Ocean from the Northwest Atlantic Shelf region off North America, to Greenland, Iceland, and the waters off of Northern Europe. In the Northwestern Atlantic, it is found in waters off western Greenland and southern Labrador, in the Strait of Belle Isle and the Gulf of St. Lawrence, off the eastern and western coasts of Newfoundland and over the Grand Banks south to the Scotian Shelf, in the Gulf of Maine and on Georges Bank. The Atlantic wolffish is a large, slow growing, and late maturing species. In the Gulf of Maine, spawning is thought to occur between September and October; incubation lasts three to nine months, depending on the water temperature (74 FR 249). Atlantic wolffish appear to prefer bottom substrates such as rocky outcroppings or seaweed beds (Collette and Klein-MacPhee 2002). West of the Scotian Shelf, wolffish abundance is highest in the southwestern portion of the Gulf of Maine from Jeffreys Ledge to Great South Channel at depths of 80 to 120 meters (260 to 330 feet) (NOAA Fisheries 2007). While it is believed to be a relatively sedentary and solitary demersal species, Collette and MacPhee (2002) suggest that feeding takes place away from its shelter sites. The Atlantic wolffish feeds primarily on benthic fauna (e.g., bivalves, gastropods, decapods, and echinoderms). Although the diet of this species shows strong regional variation, it consists mainly of various species of mollusks, crustaceans, echinoderms and less frequently, fishes. As predators, Atlantic wolffish may also be key factors in controlling density and distribution of certain benthic invertebrates, such as sea urchin (O'Dea and Haedrich 2000).

Threats to the Atlantic wolffish include incidental bycatch in otter trawl fisheries (NOAA Fisheries 2006a). Trawling and dredging activities are also believed to be responsible for degradation of wolffish habitats. The stock is considered to be overexploited and depleted.

<u>Shortnose Sturgeon</u>

The shortnose sturgeon was listed as endangered throughout its range under the Endangered Species Preservation Act of 1966. This species is also listed as a species of concern by the Committee on the Status of Endangered Wildlife in Canada (COSECWIC). Shortnose sturgeon are typically long lived, and exhibit delayed sexual maturity and high reproductive capacity. The maximum known age for females is 67 years, however males seldom exceed 30 years. Reproduction and growth characteristics vary with latitude due to the effect of differing temperature regimes, with northern populations typically exhibiting slower growth and later maturity. In the north, females typically reach maturity at 12 to 18 years of age and males at 10 to 11 years of age. The first spawning may occur 1 to 16 years after maturity, and continues annually at intervals of a few to several years. Spawning occurs in the spring at or above the head of the tide in sand to boulder sized substrate with low-medium water flow (0.2 to 1.8 m/sec). Eggs, which are laid in freshwater, hatch and larvae drift downstream and remain there for 3 to 10 years. Shortnose sturgeon then move to the freshwater/saltwater interface. Adults may occur in freshwater or tidal areas of rivers during summer and winter, where they concentrate in areas of decreased flow thought to be associated with conditions suitable for their prey. Shortnose sturgeon prefer the nearshore marine, estuarine and riverine habitat of large river systems, and rarely is found offshore. Juveniles feed on benthic macroinvertebrates and crustaceans, whereas adults feed on molluscs and large crustaceans.

The shortnose sturgeon is anadromous, living mainly in the slower moving riverine or nearshore marine waters, and migrating periodically into faster moving fresh water areas to spawn. However, unlike other anadromous species in the region, shortnose sturgeon do not appear to make long distance offshore migrations. Sturgeon are usually most abundant in estuaries, and are generally found within a few miles of land when at sea. Nineteen distinct population segments of shortnose sturgeon occur in rivers ranging from the Saint John River in New Brunswick, Canada, to the St. Johns River in Florida. Within the Northeast, DPSs include the St. John River (New Brunswick, Canada), and the Penobscot, Kennebec, and Merrimack River watersheds (table 4.6.1.1-1). Primary threats to the shortnose sturgeon are pollution and overharvesting for commercial fisheries, including bycatch in the shad fishery.

TABLE 4.6.1.1-1

**Subset of Shortnose Sturgeon Distinct Population Segments in the Northeast**

| DPS | Streams within DPS |
|---|---|
| St. John River | St. John River, New Brunswick, Canada |
| Penobscot River | Dennys, Machias, East Machias, Penobscot, Ducktrap |
| Kennebec River | Sheepscot, Kennebec, Androscoggin, Royal, Presumpscot, Saco, Kennebunk, York |
| Merrimack River | Merrimack River |

<u>Atlantic Sturgeon</u>

On January 31, 2012, NOAA Fisheries issued a final determination that lists the Atlantic sturgeon as threatened for the Gulf of Maine DPS (77 FR 5880). The remaining four DPSs (New York Bight, Chesapeake Bay, Carolina, and South Atlantic) have been listed as endangered. This species is not listed in Canada.

The Atlantic sturgeon is a long lived, late maturing, estuarine dependent, anadromous species. It spawns in freshwater, but spends most of its adult life in the marine environment. Females may live to over 60 years; however, males are thought to live about 30 years. Spawning adults migrate upriver from April to May in mid-Atlantic waters and May to July in Canadian waters. This species is highly migratory. Atlantic sturgeon spawning is thought to occur in large rivers where flow rates are between 1.5 to 2.5 feet per second (ft/s) and depths of 36 to 89 feet. Sturgeon eggs adhere to hard bottom substrates (e.g., cobble), and hatch 4 to 6 days later. Newly hatched larval fish begin migrating downstream to rearing habitats after 8 to 12 days; as it develops into the juvenile stage, it continues moving downstream into brackish waters, and eventually become a resident in estuarine waters for months or years. Subadults move to coastal waters after reaching lengths of 30 to 36 inches. Despite its extensive migrations, the adult sturgeon returns to its natal stream for spawning. Males return first and remain in the natal stream for the entire spawning period, whereas females leave the spawning grounds soon after eggs are laid (Atlantic Sturgeon Status Review Team 2007). Spawning intervals are irregular; males are thought to spawn every one to five years, and females every two to five years.

The growing demand for caviar in the 1870s is largely responsible for the intense pressures on this fishery, ultimately causing its collapse by 1901. The Atlantic sturgeon fishery was closed by the Atlantic States Marine Fishery Commission in 1998, when a coastwide fishing moratorium was imposed. Pollution, habitat degradation (e.g., dewatering of streams, changes in physiochemical properties of streams, and physical alteration of in-stream habitats), fishing exploitation in spawning habitats, and as bycatch in marine fisheries all represent critical threats to this species. Additionally, individuals are susceptible to vessel strikes (Atlantic Sturgeon Status Review Team 2007).

The Atlantic sturgeon is currently present in 35 rivers, and spawning occurs in at least 20 of these rivers (Atlantic Sturgeon Status Review Team 2007). The geomorphology of most small coastal rivers in Maine is not sufficient to support Atlantic sturgeon spawning populations, except for the Penobscot and the estuarial complex of the Kennebec, Androscoggin, and

Sheepscot Rivers. During the summer months, the salt wedge intrudes almost to the site of impassable falls in the St. Croix River (river kilometer [rkm] 16), Machias River (rkm 10), and the Saco River (rkm 10). The Atlantic Sturgeon Status Review Team note that in the St. Croix River, spawning habitat is largely lacking because of this salt wedge. Although surveys have not been conducted to document Atlantic sturgeon presence, subadults may use the estuaries of these smaller coastal drainages during the summer months.

**Marine Mammals**

Informal consultation with NOAA Fisheries and Maine DIFW determined that six threatened or endangered species of whale, including North Atlantic right, fin, humpback, sei, blue, and sperm, are known to or potentially occur within the proposed project area. Toothed whales, such as the sperm whale, feed on invertebrates and fish, whereas baleen whales filter zooplankton and small fish from the water column. As described in section 4.5.2.1, five other species of marine mammal are likely to occur in the project area, including minke whale, gray seal, harbor seal, harbor porpoise, and white-sided dolphin and are protected by the MMPA. Depending on the species, cetaceans can perceive sounds between 10 and 150,000 Hz. Peak underwater sound detection in most baleen whales is within the range of 10 to 10,000 Hz. Toothed whales emit various sounds, including tonal whistles, pulsed sounds, and less distinct pulsed sounds.

<u>North Atlantic Right Whale</u>

The North Atlantic right whale is the most endangered large whale species in the world. This species was originally protected by the 1931 Convention for the Regulation of Whaling, which took effect in 1935. It has been further protected from commercial whaling by the International Whaling Commission since 1949, Endangered Species Conservation Act since 1970, the ESA and the MMPA since 1973 (NOAA Fisheries 2005b). The World Conservation Union (IUCN) listed the North Atlantic right whale as endangered in 1986 and it still possesses this status (IUCN 2005). In 2008, NOAA Fisheries listed the northern right whale (*Eubalaena spp*.) as two separate, endangered species: the North Pacific right whale (*E. japonica*) and the North Atlantic right whale (*E. glacialis*) (73 FR 12024). This species is designated as endangered in the state of Maine and by SARA. Federal law prohibits approaching a right whale within 500 yards, and as of December 2008. Vessels of 65 feet or greater in length are required to restrict speeds to 10 knots when traversing seasonally managed areas (50 CFR Part 224). In 1994, NOAA Fisheries designated three critical habitats for the North Atlantic right whale, including coastal Florida and Georgia (Sebastian Inlet, FL to the Altamaha River, GA), the Great South Channel (east of Cape Cod), and Massachusetts Bay and Cape Cod Bay. In 2009, NOAA Fisheries and Oceans Canada designated critical habitats in Grand Manan Basin (in the Bay of Fundy) and in Roseway Basin (off the Scotian Shelf). Recent observations by NOAA's Northeast Fisheries Science Center may be evidence of a wintering ground and potentially a breeding ground over Jordan's Ledge, an area in the Gulf of Maine about 70 miles from Bar Harbor (NOAA 2008). Currently, the greatest threats to North Atlantic right whales are vessel collisions and fishing gear entanglement.

The North Atlantic right whale is highly migratory. This species ranges between southeastern U.S. coastal waters during overwinter and calving and New England waters northward to the Bay of Fundy and the Scotian Shelf to visit nursery areas and summer feeding grounds (Waring et al.

2006). Recent years have seen an increase in reported calf production, peaking at 39 reported calves in 2009 with only a single calf mortality (NOAA Fisheries 2010; Waring et al. 2010).

In spring, peak abundance occurs in the Great South Channel (Kenney et al. 1995; Kenney et al. 2001), an area east of Cape Cod. In summer and fall, the majority of the right whale population occurs in the Bay of Fundy and the Scotian Shelf (Kenney et al. 2001; Winn et al. 1986; Stone et al. 1990). Mother/calf pairs are also observed in the Bay of Fundy in the summer and fall, whereas juvenile and adult males are primarily observed in the Roseway Basin/Browns Bank region (Brown et al. 2001). The western North Atlantic population size was estimated to be at least 444 individuals in 2009 (Waring et al. 2012) based on a census of individual whales identified using photo-identification techniques.

In the western North Atlantic, right whales feed primarily on copepods, with *Calanus finmarchicus* believed to be the primary prey (NOAA Fisheries 2005b). Right whale food resources vary widely through space and time, resulting in multiscale patches of resources (EPA 1993); whale movements are thus tied to locations of this preferred prey. In the lower Bay of Fundy and in Roseway Basin, the occurrence of right whales was associated with discrete layers of *C. finmarchicus* located in the bottom mixed layer of the water column (Baumgartner et al. 2003).

North Atlantic right whales are known to occur in Head Harbour Passage, Friar Roads, Western Passage, and Grand Manan Channel (MacKay 2006; SENES 2007). Designated critical habitats for this species includes portions of Cape Cod Bay and Stellwagen Bank, the Great South Channel (each off the coast of Massachusetts), and waters adjacent to the coasts of Georgia and the east coast of Florida (50 CFR Part 226). The Canadian Department of Fisheries and Oceans also designated critical habitat for the North Atlantic right whale, including the Grand Manan Basin and Roseway Basin conservation areas. Documented sightings of the North Atlantic right whale are shown in Appendix F, figures F-24 through F-29. The SENES Report (2007) also provides documented sightings and notes that six North Atlantic right whales were observed in 2003-2004 within a 10-mile radius of Head Harbour Light[11].

Fin Whale

The fin whale has been federally listed in the United States as endangered since 1970, and in Canada the Atlantic population is listed by COSEWIC as a species of special concern. Threats to fin whales include entanglement in gillnets and vessel strikes.

Fin whales are found in temperate zones of the North Atlantic; however, they are known to migrate as far south as the Gulf of Mexico and the Mediterranean Sea. Fin whales are the most common large baleen whale species along the Atlantic coast between Cape Hatteras and Nova Scotia (Waring et al. 2010). They have the largest standing stock and the largest food requirements, thus having the largest impact on the ecosystem of any cetacean species (Kenney et al. 1997; Hain et al. 1992; Waring et al. 2010). The waters off New England represent a major feeding ground for fin whales, and evidence indicates that female whales show site fidelity for feeding areas by showing patterns of seasonal occurrence and annual returns (Waring et al. 2010). Typical prey species include sand lance, capeline, krill, herring, copepods and squid (Mitchell 1974; Katona et al. 1977). The distribution of sand lance (*Ammodytes* spp.) has a

[11] Head Harbour Light is located on Head Harbour Island, a small island located north of Campobello Island.

strong influence on the distribution and movement of fin whales along the eastern coast (Reeves et al. 1998; Wilson and Ruff 1999; EPA 1993).

Fin whales are the most abundant and frequently sighted of the endangered great whales known to visit the Passamaquoddy Bay area (Waring et al. 2010; SENES 2007). This species is also known to occur in the waters of the outer Quoddy region, Head Harbour Passage, Friar Roads, and Western Passage (MacKay 2006; SENES 2007). Fin whale observations are common during summer and fall; documented sightings were made by the Quoddy Marine Link (a whale watching vessel) in Blacks Harbour, Bliss Island, Whitehorse and near Head Harbour Light on the northern tip of Campobello Island (Quoddy Marine Link 2008). The comments of Save Passamaquoddy Bay note that fin whales are frequently observed in Head Harbour Passage. Documented sightings of the fin whale are shown in Appendix F, figures F-21 and F-24.

<u>Humpback Whale</u>

The humpback whale has been federally listed as endangered since 1970 in the United States; however, the western North Atlantic humpback whale population is designated as “not at risk” in Canada.

The humpback whale is found in all the world’s oceans, including (but not limited to) the east coast of the United States, the Gulf of St. Lawrence, Newfoundland/Labrador, and western Greenland (Katona and Beard 1990). It inhabits waters over the continental shelf and around some of the oceanic islands (Wilson and Ruff 1999; NOAA Fisheries 1991, 1993). Abundance estimates for the Gulf of Maine humpback whale sub-population has proved to be challenging due to the overlap in range of some of the stocks. The best abundance estimate for the Gulf of Maine stock is 847, with a minimum estimation of 359 animals (Waring et al. 2010).

Humpbacks feed in temperate and polar waters in the summer, and mate and calve in tropical waters during the winter. Summer feeding takes place mainly while in areas over the continental shelf between New Jersey and Greenland. Prey species consist of small schooling fish such as sand lance, herring, capelin, and sometimes mackerel. Humpback whales reach peak abundance in New England waters during May and June, and remain there until October. Large numbers of humpbacks occur around the mouth of the Bay of Fundy from July through October (NOAA Fisheries 1991). MacKay (2006) noted occurrence of this species in the outer Quoddy region and Head Harbour Passage; however, this species is not expected to occur near the Western Passage. Documented sightings of the humpback whale are shown in Appendix F, figures F-23 and F-24.

<u>Sei Whale</u>

The sei whale is a federally listed endangered species in the United States. In Canada, the Atlantic population of this species is designated as “Data Deficient.”[12] Threats to sei whales include vessel collisions and physical and acoustic harassment.

The range of the Nova Scotia stock of sei whales includes waters of the Scotian Shelf during the feeding season and extends southward into the Gulf of Maine and Georges Bank during spring and summer (Waring et al. 2010). Concentrations of sei whales tend to occur in deeper waters as

[12] Data Deficient is defined by the Committee on the Status of Endangered Wildlife in Canada as a species for which there is insufficient scientific information to support status designation.

in regions of the continental shelf edge, but this offshore pattern also includes travel into more shallow and inshore waters (Waring et al. 2010).

The sei whale appears to prefer temperate, deep offshore habitat more than other species of large baleen whales. During times of high prey abundance, this baleen whale may be found in inshore waters. Sei whales have been observed in areas that would be transited by vessels along the proposed waterway for LNG marine traffic. This species may be present as transient individuals near Western Passage. Documented sightings of the sei whale are shown in Appendix F, figure F-24 and F-30.

Blue Whale

The blue whale has been federally listed as endangered in the United States since 1970 and is also considered endangered in Canada (COSEWIC 2002). Historic threats to blue whales were from whaling activities. The Recovery Plan for the blue whale describes potential anthropogenic impacts, including vessel collision; physical and acoustic harassment; fishing gear entanglement/entrapment; and degradation of habitat. NOAA Fisheries (1998) indicates that blue whales are occasionally killed or injured after colliding with a vessel. Blue whales are currently of interest for tour boats in Canada, but not in the United States.

The distribution of blue whales is thought to be dependent on prey abundance and location. This species is frequently sighted in waters off eastern Canada with most of the recent records being in the Gulf of St. Lawrence (COSEWIC 2002; NOAA Fisheries 1998; Sears et al. 1987; Waring et al. 2002). Blue whales occur in the Gulf of St. Lawrence during the spring, summer, and autumn months, mostly along the north shore from the St. Lawrence River estuary to the Strait of Belle Isle and off eastern Nova Scotia (Reeves et al. 2005; Waring et al. 2010). In the winter, this stock is found off the coast of southern Newfoundland (Waring et al. 2010). In general, little is known about the blue whale population size with the exception of this Gulf of St. Lawrence area, in which 440 individuals were catalogued from 1979 to 2009 by R. Sears (as reported in Waring et al. 2010).

Sperm Whale

The sperm whale is a federally endangered species within the United States; however, it is not listed in Canada. The greatest threats to sperm whales currently include vessel strikes, entanglement in fishing gear, changes in prey populations, habitat degradation, disturbance from high frequency noise, and possibly biomagnifications of pollutants (NOAA Fisheries 2006b).

Sperm whales are found along the continental shelf edge, over the continental slope and into the mid-ocean regions. Most sperm whale sightings on the East Coast have occurred along the edge of the continental shelf, where dense concentrations of large squid, its preferred prey, occur (Wilson and Ruff 1999). During winter months, sperm whales concentrate east and northeast of Cape Hatteras, North Carolina (Waring et al. 2007). In spring months, this species migrate towards Delaware, Virginia, and the central portion of the mid-Atlantic bight and southern section of Georges Bank (Waring et al. 2007). During summer months, sperm whales are also found east and north of Georges Bank, into the Northeast Channel region and over the continental shelf south of New England (Waring et al. 2007).

## Reptiles

Leatherback Sea Turtle

Leatherback sea turtles are known to occur off the coast of Maine and are listed as endangered by the ESA. The leatherback sea turtle is also listed by COSEWIC as endangered. Unchecked harvest of leatherback sea turtle meat and eggs, as well as incidental bycatch in commercial fishing, are the primary causes for the decline of this population (FWS 2005); other factors such as degradation of foraging habitat, marine pollution and debris, and vessel strikes also contributed to its decline (FWS 2005; NOAA Fisheries 2006). During summer months, the distribution of the leatherback sea turtles includes the Gulf of Maine, along the coast of Maine and northward to Nova Scotia and the Labrador coast (Stellwagen Bank 2006; Maine DIFW 2003a). Recent telemetry studies identified high-use areas in continental shelf and slope waters off of eastern Canada and the northeastern United States, including waters off the eastern coast of Nova Scotia and in the Gulf of St. Lawrence. In the fall, leatherbacks move offshore and begin their migration south to wintertime breeding grounds; however, they do not use consistent migration corridors. Leatherbacks tagged with satellite transmitters at sea off the coast of Nova Scotia were tracked to waters adjacent to nesting beaches along the northeast coast of South and Central America (James et al. 2005).

The Gulf of Maine is classified as an important feeding area for leatherback sea turtles. Leatherback sea turtles are expected to be present in feeding areas and surrounding habitat, including Passamaquoddy Bay and the Bay of Fundy during the summer and fall (typically June through October). Critical habitat was designated for the leatherback sea turtle in 1998 for leatherback turtles in coastal waters adjacent to Sandy Point, St. Croix, U.S. Virgin Islands.

### 4.6.1.2 State-Listed and Other Special Status Species

## Birds

Bald Eagle

The bald eagle is listed as threatened in Maine and was recently delisted as federally threatened effective August 8, 2007. The FWS has stated that the best available scientific and commercial data available indicates that the bald eagle has recovered, in part, because of actions taken from the regional recovery plans for the bald eagle (2007 FR 37346). For each of these regions, the bald eagle has achieved or surpassed the federal delisting or recovery criteria. However, there are additional state delisting criteria that include maintaining a “safety net” of habitats (i.e., >150 habitats under conservation ownership, appropriate easements, or cooperative management agreements) that are yet to be achieved (Maine DIFW 2004). Bald eagles are still afforded federal protection under the Bald and Golden Eagle Protection Act. Bald eagles are not listed in Canada.

The bald eagle is a bird of aquatic ecosystems inhabiting estuaries, large lakes, reservoirs, major rivers, and some seacoast habitats. Nesting and breeding habitat requirements include large trees and areas that consist primarily of old white pine in Maine; these habitats generally are located near water (e.g., waterways including sea coasts, lakes, and rivers) for foraging. Eagles are opportunistic feeders, consuming mostly fish and also birds, small mammals and reptiles, and carrion. In remote settings, eagle pairs can be sensitive to disturbance during the nesting season, typically from February through August. Limited human activity is preferable; however, normally occurring noise has shown to be non-disruptive to eagle behavior (Stalmaster and Newman 1978). In winter, bald eagles often congregate in large numbers along streams to feed on spawning salmon or other fish species.

### 4.6.2 Impacts and Mitigation

#### 4.6.2.1 Waterway for LNG Marine Traffic

**Federally Listed Species**

Atlantic Salmon

Atlantic salmon adults are common in Passamaquoddy Bay from May through November, and juveniles are common from April through June. Dube (2006) of the Maine ASC reports that during 2003 and 2005, a maximum of 42 returning salmon per year were sampled from the St. Croix River; of this number, most individuals were determined to be escaped hatchery-reared salmon. This relatively low number of documented returning non-hatchery reared salmon to the St. Croix River noted by Dube (2006) indicates that, while this species does occur in the waterbodies associated with the waterway for LNG marine traffic, its presence would likely be low. Migratory salmon present in the waterway may be temporarily displaced to adjacent waters by disturbance caused by LNG vessels; however, this displacement is expected to be short term and localized. We received a letter from NOAA Fisheries, dated November 16, 2006, that concurred with this assessment. Atlantic salmon adults may occur within the waterway for LNG marine traffic, but are unlikely to be adversely affected by the proposed project.

Atlantic and Shortnose Sturgeon

The Atlantic Sturgeon Status Review Team (2007) notes that a small spawning population of large Atlantic sturgeon may be present in the St. Croix River below the hydroelectric dam. Few spawning adults are anticipated to be present in the St. Croix River; however, subadults may use Passamaquoddy Bay in summer months. The shortnose sturgeon is not documented in the St. Croix River system or coastal waters near Passamaquoddy Bay, with the closest documented population is in the Penobscot River over 100 miles south of the Project area. However, ongoing studies show that at least some population of shortnose sturgeon in Maine undergo coastal migrations between river systems, and NOAA Fisheries (2012) suggests that although undocumented, the shortnose sturgeon may occur in the same rivers as the Gulf of Maine DPS of the Atlantic sturgeon.

It is possible that Altantic or shortnose sturgeon could be present in the waterway during project operation and could be temporarily displaced to adjacent waters by disturbance caused by LNG vessels; however, this displacement is expected to be short term and localized. It is also possible that sturgeon could be susceptible to vessel strikes (see discussion below).

Atlantic Wolffish

The Atlantic wolffish may occur within the waterway for LNG marine traffic, but is unlikely to be adversely affected by the proposed project. Impacts on demersal species such as the Atlantic wolffish are expected to be similar to those described in section 4.5.2.1 of this EIS.

Marine Mammals

Whales have been observed across the mouth of Passamaquoddy Bay from Head Harbour Passage up to Blacks Harbour on the coast of New Brunswick in July and August. Whale species have also been observed in Friar Roads, Western Passage, and Grand Manan Channel (MacKay 2006). However, because of the rarity of documented sightings, the presence of whales in the immediate area of the LNG terminal is not expected. Six species of whales protected by the MMPA are likely to be present in the waterway for LNG marine traffic. These species may be affected by vessel collisions, physical and acoustic harassment, and to a lesser extent by the introduction of pollution and artificial lighting. Potential impacts and proposed mitigation measures are discussed in further detail below; additional information about underwater noise is discussed in section 4.5.2 and 4.11.2 of this EIS.

*Vessel Strikes*

Protected whales are not commonly encountered in the waterway for LNG marine traffic; however, the increased vessel passage constitutes an increase in potential for vessel strikes to these species. Vulnerability to vessel collisions may result from the whale's limited ability to detect or maneuver around oncoming vessels, or because the species is at the surface feeding, resting, mating, and/or nursing. Research associated with vessel strikes and physical harassment indicates that most vessel collisions with whales that result in serious injury or death occur when a vessel is traveling over speeds of 14 knots (Laist et al. 2001). According to Jensen and Silber (2003), Nelson et al. (2007), and Waring et al. (2010), there have been 198 documented occurrences of vessel collisions with marine mammals in the Western Atlantic Ocean (including the United States East Coast, United States Gulf Coast, and Eastern Canada) between 1905 and 2008, most of which occurred off the United States East Coast. Table 4.6.2.1-1 lists the vessel strikes by mammal species or species group. Of strikes reported from the Western Atlantic Ocean, 82 percent occurred along the United States East Coast. Fin, humpback, and right whale collisions comprised 75 percent of these documented vessel strikes. Nelson et al. (2007) examined mortality and serious injury reports involving baleen whale stocks along the U.S. eastern seaboard between 2001 and 2005. According to this study, 11.5 percent of events involved vessel strikes, of which 64 percent resulted in mortality. Entanglement with fishing gear accounted for 32 percent of events, of which 20 percent resulted in mortality.

A review of data from the Ocean Biogeography Information System (OBIS) and the North Atlantic Right Whale Consortium (NARWC) found that various marine mammal species are known to aggregate along portions of the proposed marine transit route (see Appendix F, figures F-20 to F-30). As a result, LNG vessels transiting the route have the potential to encounter and affect marine mammals.

Fin, humpback, sei, sperm, and blue whales have experienced both injury and mortality as the result of vessel strikes within each species' habitat range (see table 4.6.2.1-1). Between 1999 and 2008, 13 fin whales of the western North Atlantic stock were killed by vessel strikes; 14 vessel strikes resulted in humpback whale mortalities; 2 sei whales were struck by transiting vessels; and 1 sperm whale was killed after colliding with a vessel (Cole et al. 2006; Waring et al. 2006; and Waring et al. 2010).

TABLE 4.6.2.1-1

**Analysis of Whale Mortality and Serious Injury Reports Associated with Vessel Strikes from the Period 1905 – 2008 a/ & b/**

| Species | Eastern Canada | U.S. East Coast | U.S. Gulf Coast | Total Individuals |
|---|---|---|---|---|
| Baleen | 0 | 1 | 0 | 1 |
| Blue | 0 | 1 | 0 | 1 |
| Fin | 7 b/ | 46 b/ | 1 | 54 |
| Humpback | 1 | 40 b/ | 1 | 42 |
| Minke | 1 | 17 | 1 | 19 |
| Minke/small sei | 0 | 1 | 0 | 1 |
| North Atlantic Right | 11 | 39 b/ | 2 | 52 |
| Sei | 0 | 6 b/ | 0 | 6 |
| Sperm | 1 | 3 | 2 | 6 |
| Unknown | 7 | 8 | 1 | 16 |
| **Total Individuals** | **28** | **162** | **8** | **198** |
| **Total Percent by Region** | **14%** | **82%** | **4%** | |

a/ Whale mortality and serious injury reports (1905 through 2005) from Jensen and Silber, 2003, and Nelson et al. 2007. Only data associated with vessel strikes are reported in this table.
b/ Numbers updated from 2005 through 2008 Waring et al. 2010, stock assessment reports. Only data associated with vessel strikes are reported in this table.

Near the project area in the Bay of Fundy between the years of 1976 and 2006, there were 25 reported right whale strikes. Of these incidences, 18 resulted in death (Jensen and Silber 2004; Marine Connection 2006; Nelson et al. 2007; Waring et al. 2008; and Waring et al. 2010). Table 4.6.2.1-2 summarizes right whale vessel strikes in the Bay of Fundy.

The proposed Downeast LNG Project would result in increased marine traffic through the Bay of Fundy to the project terminus in the Western Passage by as many as 60 vessels per year. Currently, nearby commercial ports (Port of Eastport, Maine; and Port of Bayside in Canada, near Calais, Maine) typically receive about 125 vessels each year, including ferries, small- to mid-size cruise ships, and cargo vessels. This impact reflects both a permanent increase (49 percent) in large vessel traffic and a temporary incremental increase from construction vessels to existing vessel activity associated with fishing, commercial transportation, recreational boating, and ferries.

In the project area, the primary issue of concern is the protection of the North Atlantic right whale, as the Bay of Fundy and Passamaquoddy Bay are within important habitats for this species. The major apparent threat to the North Atlantic right whale and the most probable factor preventing recovery of this species is human-caused mortality and serious injury due to vessel strikes. The current strategy to minimize impacts on the North Atlantic right whale as well as the general conservative approach to protect other marine mammals builds upon the mitigation measures developed to protect this species. The greatest protection measures for whales are avoidance measures, followed by reduced vessel speed.

| TABLE 4.6.2.1-2<br>**Identified Ship Strikes of North Atlantic Right Whales Near Gulf of Maine and Bay of Fundy** | | | | |
|---|---|---|---|---|
| **Date** | **Sex** | **Age** | **Location where struck or found** | **Mortality/Injury** |
| 1972 a/ | - | - | 97 km East of Boston, Massachusetts | Mortality |
| 04/15/1976 | M | Calf | Massachusetts | Mortality |
| 11/05/1976 | - | - | Maine | Mortality |
| 05/25/1980 | M | - | Great South Channel, Massachusetts | Injury |
| 08/05/1984 | UNK a/ | - | Browns Bank, Canada | Mortality |
| 08/14/1986 | F | - | Bay of Fundy, Canada | Presumed Mortality |
| 07/09/1987 | M | Juvenile | Nova Scotia, Canada | Mortality |
| 08/28/1987 | UNK | - | Browns Bank, Canada | Injury |
| 09/05/1992 | F | Adults | Bay of Fundy, Canada | Mortality |
| 09/16/1995 | M | 4 years | Bay of Fundy, Canada | Injury |
| 10/19/1995 | M | - | Bay of Fundy, Canada | Mortality |
| 08/19/1997 | F | - | Bay of Fundy, Canada | Mortality |
| 07/08/2000 | M | - | Bay of Fundy, Canada | Unknown |
| 09/27/2000 | F | - | Bay of Fundy, Canada | Injury |
| 10/02/2003 | F | - | Digby, Nova Scotia | Mortality |
| 04/28/2005 | F | - | Monomoy Island, Massachusetts | Mortality |
| 07/24/2006 | F | - | Campobello Island, NB Canada | Mortality |
| 08/24/2006 | F | - | Roseway Basin, Nova Scotia, Canada | Mortality |
| 09/03/2006 | F | - | Nova Scotia, Canada | Mortality |
| 04/19/2009 | UNK | - | Stellwagen Bank National Marine Sanctuary | Injury observed; fate unknown |

a/ Presumed North Atlantic right whale

Source: Glass et al. 2008; Jensen and Silber 2003; Nelson et al. 2007; and Waring et al. 2008; Waring et al. 2010; Right Whale News 2009.

NOAA Fisheries has established regulations to limit vessel speed of vessels 65 feet or longer that transit certain management areas along the U.S. East Coast (Right Whale Ship Strike Reduction Rule, 50 CFR Part 224). Evidence suggests that the likelihood of death and serious injury to large whales struck by vessels is related to vessel speed. The regulations were issued October 8, 2008 and went into effect on December 9, 2008. The regulations establish (1) Seasonal Management Areas (SMAs), which are predetermined and established areas within which a seasonal speed restriction of 10 knots would apply; (2) Dynamic Management Areas (DMAs), which are areas temporarily defined around confirmed right whale sightings, within which a voluntary speed restriction of 10 knots would apply; and (3) monitoring the use of recommended shipping routes[13]. These measures would apply only to non-sovereign vessels 65 feet or more in overall length. NOAA Fisheries has assessed speed restrictions and will likely continue, or modify these restrictions through additional rule makings (Silber and Bettridge 2012).

[13] Vessels may operate at a speed greater than 10 knots only if necessary to maintain a safe maneuvering speed in an area where conditions severely restrict vessel maneuverability as determined by the pilot or master.

On June 1, 2009, the International Maritime Organization (IMO) adopted a proposal that would limit interactions between whales and transiting vessels of 300 gross tons or more during times of high whale abundance. The Great South Channel Area to be Avoided (ATBA), in waters east of Massachusetts, is feeding habitat for the North Atlantic right whale and occurs in designated critical habitat for that species. The ATBA would be in effect from April 1 through July 31 of any year. This measure is anticipated to reduce the likelihood of vessel strikes to whales by 63 percent.

Similar protective measures to whales have been implemented by Canada and adopted by the IMO. The Bay of Fundy is an important transit route with traffic lanes for about 800 vessels passing to and from Canadian and U.S. ports annually, resulting in significant vessel traffic across the Canadian Grand Manan Basin Whale Sanctuary. Over two-thirds of the known population of North Atlantic right whale is found in the Bay of Fundy area during June through November. A change in the mandatory shipping lanes in the Bay of Fundy was proposed and adopted by Canada's Maritime Safety Committee in 2002 (IMO 2002, 2007); this measure was designed to relocate vessel traffic using the traffic separation scheme from an area with a high density of right whales to an area with a lower density (3.9 miles to the east), thus reducing the relative probability of a vessel strike by approximately 62 percent (Vanderlaan et al. 2008). On June 1, 2008, Transport Canada adopted the "Roseway Basin ATBA, South of Nova Scotia," originally proposed by the IMO on April 20, 2007 (IMO 2007). The Roseway Basin ATBA would have only a seasonally limited effective period of seven months (June through December) each year when the largest percentage of the right whales is known to be in the area, and consequently when the risk of vessel strikes is greatest. The voluntary implementation by mariners of the ATBA is expected to reduce the probability of a lethal vessel-whale encounter by at least 82 percent (van der Hoop et al. 2012).

Because LNG vessels associated with the proposed Downeast LNG Project could transit waters designated by the IMO and the NOAA Fisheries as natural habitat of the right whale, the LNG vessels would follow the IMO regulations to report any sightings of right whales and to undertake precautionary measures to avoid any contact with the species. Specifically, LNG vessels would remain 500 yards (457 meters) away from North Atlantic right whales and 100 yards (91 meters) away from all other whales when navigational limits permit. Vessels would comply with IMO regulations to avoid the Great South Channel ATBA during April through July. The IMO also recommends voluntary compliance with the Roseway Basin ATBA and the Bay of Fundy traffic separation scheme. As previously described, mandatory speed restrictions of 10 knots or less are required in SMAs during times when North Atlantic right whales are likely to be present, with certain exceptions. Furthermore, LNG vessels could avoid the Canadian designated Grand Manan Basin Whale Sanctuary (see Appendix F, figure F-19) if right whales are known to be in the area by transiting along the western side of Grand Manan Island. Downeast LNG terminal construction and operation crews would also receive environmental training that stresses individual responsibility for marine mammal awareness and reporting. All on-board crew members would receive training on marine mammal sighting and reporting, as required by IMO standards. Additionally, the captains/pilots of LNG vessels associated with the proposed Downeast LNG Project would be responsible for monitoring communications and for sighting reports of the North Atlantic right whale, including local Notice to Mariners, Navigational Telex (NAVTEX) warnings, NOAA Weather Radio, and any other means. Following a received whale sighting warning, LNG vessels would comply with required

IMO regulations and federal regulations, and all attempts to avoid contact and reduce the risk of vessel strikes to whales would be made. In the event that a vessel strike occurs, the appropriate NOAA Fisheries Regional Stranding Coordinator would be notified and the crew would follow the ensuing procedural guidance.

Downeast continues to consult with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss appropriate mitigation measures and to develop a complete and comprehensive Prevention and Mitigation Manual for the construction and operation of the project. Downeast has proposed that the following mitigation measures be implemented during all stages of the project, maximizing protection of the listed species by either avoiding adverse impacts, or minimizing the potential for adverse impacts:

- Per NOAA Regulation (50 CFR Part 224.103) all vessels are prohibited from approaching closer than 500 yards to any right whale. For all other whales, vessels are prohibited from approaching closer than 100 yards.

- If not otherwise required by international law, all LNG vessels, or vessels involved with the terminal construction, navigating Grand Manan Channel would establish communications upon entering the channel, or when crossing a line drawn between Cutler, Maine and the southwestern tip of Grand Manan Island (GMI), or approximately 44.6° north latitude. Vessels departing the Downeast LNG terminal via the Grand Manan Channel would establish communications prior to getting underway and maintain communications until south of southwestern tip of GMI.

- As an extension of ship strike rules (50 CFR Part 224.105 ) in U.S. waters, all vessels over 65 feet (19.8 meters) involved with construction, or future operations of the Downeast LNG Terminal would slow to 10 knots upon entering Grand Manan Channel, on a line drawn between Cutler, Maine and the southwestern tip of GMI, or approximately 44.6° north latitude. Vessels departing the Robbinston terminal via the Grand Manan Channel would not exceed 10 knots until south the previously specified latitude.

- All vessels over 65 feet (19.8 meters) navigating the Bay of Fundy (BOF) Traffic Separation Scheme that are involved with construction, or future operations of the Downeast LNG Terminal would slow to 10 knots upon northwesterly course adjustment near 44.5° north latitude. Vessels bound for the Robbinston terminal would remain at 10 knots or slower until their arrival at the terminal, or until control is relinquished to a tug. Vessels departing the Robbinston terminal via the BOF Traffic Separation Scheme would not exceed 10 knots until after making the southwesterly course adjustment near 44.5° north latitude.

- The use of “forward-watching” whale spotters that would be ahead of the LNG vessel transitway and on the LNG vessel. The spotters would warn of North Atlantic right whale presence, especially in Head Harbour, as well as other observed special status species. This practice is used for protected species at the EcoElectrica LNG Import Terminal in Puerto Rico and has reportedly been very successful. The intent of the forward-watching whale spotters is to notify an LNG vessel in advance of the vessel entering an area of the presence of a North Atlantic right whale and to defer entry.

A similar practice is already in place in the area relative to the pilots and their advance ship radio communication. The Downeast plan would implement a dedicated team of whale spotters and a vessel that would be resident to the area (e.g., personnel and equipment/vessel located in Eastport-Perry and/or Canada). This team could also be used in coordination with local whale observation recorders to regularly monitor and record whale sightings. The spotter vessel would precede the LNG vessel by approximately one mile so as to warn the larger vessel of any whales in their path.

- Development and implementation of a project-wide training and education program, wherein all employees of the project and LNG vessel crews are provided detailed information regarding the potential presence of special status species and methods and procedures to avoid problematic encounters.
- Providing specialized equipment that would enhance the identification and locating of protected species, especially the presence of North Atlantic right whale. Investigations are being conducted regarding this type of equipment, which may include instrumentation that uses infrared methods for identification.
- Funding of enhanced visual observation equipment for placement on whale watching tour vessels that would promote customer observation of encountered whales from a greater distance than might be practiced at present.

These measures that Downeast would employ to minimize impacts on North Atlantic right whales would minimize impacts on all listed cetateans as well as sea turtle and sturgeon species. Downeast has committed to continue its consultation with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss appropriate mitigation measures. Upon completion of ESA consultation and federal and state permitting processes, Downeast would incorporate the final approved construction and mitigation measures into a comprehensive Prevention and Mitigation Manual for use in training of Downeast's construction and operational personnel, which would be filed with FERC.

*Acoustic Take and Harassment*

Marine ocean noise has increased in recent years, due in large part to anthropogenic sources such as shipping, seismic profiling for oil/gas exploration or seismic/geologic hazard exploration, and drilling and pile driving among others. Some of these sounds are loud enough to cause physical injury or elicit behavioral changes in the marine organisms that perceive those sounds, particularly marine mammals. The MMPA of 1972 prohibits with limited exceptions the take of marine mammals in waters or on lands under U.S. jurisdiction. It also regulates the take of marine mammals on the high seas by vessels or persons under U.S. jurisdiction. A "take" is defined as "harass, hunt, capture, or kill, or attempt to harass, hunt, capture or kill any marine mammal. The MMPA defines 'harassment' as any act of pursuit, torment, or annoyance that either has the potential to injure a marine mammal or marine mammal stock in the wild (Level A harassment, generally assumed to occur at 180 dB re 1 μPA for cetaceans and 190 dB re 1 μPA for pinnipeds), or has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering (Level B harassment, generally assumed to occur at 160 dB re 1 μPA for pulsed noise, or 120 dB re 1 μPA for continuous noise).

Many marine mammals rely on sound for navigation, communication, and detection of prey (by echolocation). Thus, the generation of project-related anthropogenic noise may affect a mammal's ability to perform some or all of these important functions. Specifically, noise created by LNG vessels in transit may cause temporary changes in marine mammal behavior. The cumulative impact of increased vessel traffic resulting from the marine projects in the area is discussed in sections 4.11.2 and 4.13 of this EIS. In the presence of vessels, whales may exhibit no response; they may exhibit avoidance response; or they may exhibit behaviors that increase their susceptibility to collision, such as startle responses, erratic surface movements, reduced surface time, fewer blows per surfacing, shorter intervals between successive blows, and increased frequency of dives without raised flukes (Whitehead et al. 1990; Cawthorn 1992; Gordon et al. 1992). Of the whale species that could occur in the project area, the fin whale is known to react strongly to low-frequency vessel sounds that are near the frequency of its own vocalizations, between 15 to 100 Hz (EPA 1993). In 1979 to 1980, fin whales were reported to actively avoid approaching vessels within this sound range, especially those that approached quickly or changed direction or speed abruptly (Edds and Macfarlane 1987; Macfarlane 1981 as reported in Richardson et al. 1995).

Marine mammals have shown a response to constant low-frequency received sounds with broadband intensities of more than about 120 dB re 1 μPa (Richardson et al. 1995). However, actual thresholds for behavioral responses to sounds in the natural environment depend largely on the level of natural ambient noise, with whales apparently capable of distinguishing sounds in their optimum frequency range that are 10 to 20 dB re 1 μPa above ambient noise at the same frequency (Richardson et al. 1991).

To estimate the effects of underwater sound propagation produced during construction and operation of the proposed project on marine wildlife, Downeast conducted a comprehensive underwater acoustic modeling analysis (Gaboury et al. 2007). Results of this study are discussed in detail in section 4.11.2. Vessels and tugs used to transit the waterway for LNG marine traffic would likely generate sound source levels in the range of 120 to 160 dB re 1 μPA at 1 meter proportionate to vessel size, depth of propeller, speed, engine load and revolutions per minute with broadband source levels driven primarily by propeller cavitations, hydrodynamic flow over the hull and hull appendages, and operation of machinery onboard. Therefore, sounds generated by project vessels transiting could potentially elicit a short-term avoidance response by marine mammals in the area. While Level A acoustic harassment is possible, marine mammals are unlikely to remain close enough to the transiting vessel or associated tugs to be affected in that manner; it is widely assumed that most marine mammals would flee the immediate area adjacent to a vessel. However, Level B acoustic harassment caused by transiting vessels and tugs is expected to affect marine mammals that are present in the waterway for LNG marine traffic.

Downeast has consulted with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss appropriate mitigation measures. Appropriate mitigation measures are also part of the FWS and NOAA Fisheries review of the BA. Mitigation measures would be implemented during all stages of the project, maximizing protection of the listed species by either avoiding adverse impacts, or minimizing the potential for adverse impacts.

*Physical Harassment*

To date, the overall impacts on marine mammals associated with exposure to toxins are not well understood; however, accidental spills and releases of oils, lubricants or other pollutants could harm those species that come into contact with the released product. For example, biomagnifications of environmental toxins (e.g., ingestion of phytoplankton toxins like saxitoxin) have been known to pose threats to whales such as humpback and sperm whales. To minimize the potential for accidental spills and/or releases, as well as the associated impacts on marine mammals, LNG vessels would comply with Coast Guard regulations (33 CFR § 151, 155, and 157 regarding implementation of MARPOL 73/78) and VGP requirements. Downeast would also adopt marine spill prevention and control measures to expedite containment and cleanup in the event of a spill at the LNG terminal. As such, marine mammals are not expected to be adversely affected by accidental spills.

Certain types of anthropogenic debris and refuse have also been documented to cause harm to marine species, such as plastic bags swallowed by feeding whales, plastic six-pack straps wrapped around the necks of waterfowl, etc. To prevent such impacts, Downeast would provide guidance to facility personnel regarding the proper disposal requirements for debris and other refuse.

Lights on LNG vessels and support vessels would be necessary to ensure safe operation at all times, and could attract potential whale prey species to the area. However, lighting is not expected to significantly alter the behaviors of marine mammals in the waterway for LNG marine traffic.

In summary, the proposed waterway for LNG marine traffic has the potential to affect each federally listed whale species, either through physical or acoustic harassment. LNG vessels would comply with IMO regulations and the Ship Strike Reduction Rule when in jurisdictional waters to reduce the threat of vessel collisions with North Atlantic right whales. Underwater noise generated by LNG vessels and support and construction vessels transiting the area would result in an overall increased exposure to anthropogenic noise. However, since the project would be located in an area with shipping activity, exposure to noise would be consistent with existing conditions. Downeast notes that the noise of marine vessels in the transit area is not uncommon; motorized vessel traffic and recreational boating have occurred in this area during the last 100 years. However, the additional LNG vessels and associated escort and security boats would be a change to the type and amount of existing ship traffic along the LNG vessel transit route and in Mill Cove. Underwater noise produced by vessels that transit the waterway for LNG marine traffic is not likely to adversely affect federally listed whales. Noise associated with project construction activity and construction vessel transit, particularly when engine thrusters are operating and during pile driving operations, may adversely affect whales by eliciting a startle response, masking of marine mammal sounds, or result in area avoidance.

Impacts and mitigations to federally listed whales are also discussed in the BA (see Appendix C).

Leatherback Sea Turtle

Along the waterway for LNG marine traffic, the greatest potential impacts on leatherback sea turtles are vessel strikes and acoustic harassment, followed by pollution. Sea turtles are difficult to spot from transiting vessels and are especially prone to propeller strikes. Downeast has indicated that it would provide environmental training to vessel crews to identify threatened and endangered species; during inclement weather and periods of low visibility, LNG vessels would be required to reduce speed to allow for safe operation of the vessel and crew. In addition, mitigation measures that Downeast would implement to protect North Atlantic right whales would also be applied to sea turtles. Downeast's implementation of reduced vessel speed would act to reduce both the noise emitted from the vessel as well as the potential for turtle-vessel encounters. With these mitigations in place, the waterway for LNG marine traffic is not likely to adversely affect leatherback sea turtles.

**State-Listed and Other Special Status Species**

Bald Eagle and Bald Eagle Essential Habitat

Review of Maine GIS habitat maps for the bald eagle indicates eight current or historic nesting sites near the waterway for LNG marine traffic (Appendix F, figures F-14 through F-16). During normal conditions, passing LNG vessels would not affect nesting bald eagles, bald eagle nesting habitat, or potential food sources.

### 4.6.2.2 LNG Terminal

**Federally Listed Species**

Leatherback Sea Turtles

Leatherback sea turtles have the potential to be affected by construction and operation of the proposed LNG terminal. As discussed in section 4.6.2.1, measures to avoid impacts on whales would also benefit leatherback sea turtles.

Downeast would employ at least one full-time EI during construction. Downeast has stated that this individual would be experienced with offshore and onshore construction and would have experience with marine mammal and sea turtle mitigation measures. Prior to commencing construction activities, Downeast has stated that the EI would search the work area for the presence of sea turtles. If a sea turtle were sighted, work would be delayed until the EI provided procedures to the work crew to avoid harassment of the animal. Given the rarity of sea turtle sightings within the immediate vicinity of the proposed project, it is unlikely that acoustic harassment caused by construction and operation of the LNG terminal (described below) would adversely affect leatherback sea turtles.

Atlantic Salmon

The proposed LNG terminal is located in the vicinity of the migratory corridor for adult salmon and juvenile salmon smolts moving to and from the St. Croix River. Within the project region, Atlantic salmon use Passamaquoddy Bay, the St. Croix, Dennys, and Pennamaquen rivers as a migratory corridor. Within the Dennys River, this species spawns and rears its young. Comment letters during the scoping process have expressed concern for migrating smolts in the vicinity of the LNG terminal. In a communication to the FERC on November 16, 2006, the FWS and NOAA Fisheries indicated that transient Atlantic salmon may occur in the vicinity of the proposed LNG terminal.

Atlantic Sturgeon

The Atlantic Sturgeon Status Review Team (2007) notes that a small spawning population of Atlantic sturgeon may be present in the St. Croix River below the hydroelectric dam; however, it also notes that spawning habitats are largely lacking because the salt water wedge intrudes nearly to the impassable falls at river mile 9.94. Few spawning adults are anticipated to be present in the St. Croix River; however, subadults may use Passamaquoddy Bay in summer months.

Downeast has consulted with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss appropriate mitigation measures. Appropriate mitigation measures are also part of the FWS and NOAA Fisheries review of the BA. Mitigation measures would be implemented during all stages of the project, maximizing protection of the listed species by either avoiding adverse impacts, or minimizing the potential for adverse impacts. Downeast has proposed that underwater noise levels must be mitigated for to ensure that the extent of the 150 dB re 1μPa RMS isopleth (i.e., the level of underwater noise believed to cause behavioral modification in sturgeon) does not prevent passage of listed Atlantic sturgeon within the affected waterbody. While individuals may be displaced from, or avoid, the ensonified area, there must always be a zone of passage where noise levels remain below 150 dB re 1μPa RMS.

Shortnose Sturgeon

The shortnose sturgeon is not documented in the St. Croix River system or coastal waters near Passamaquoddy Bay. The closest documented population is in the Penobscot River over 100 miles south of the Project area. However, ongoing studies show that at least some population of shortnose sturgeon in Maine undergo coastal migrations between river systems, and one individual was detected in 2010 in the Narraguagus River, about 60 miles south of the Project area (Zydlewski et al. unpublished). NOAA Fisheries (2012) also suggests that although undocumented, the shortnose sturgeon may occur in the same rivers as the Gulf of Maine DPS of the Atlantic sturgeon. The historic and current status of the St. Croix Atlantic sturgeon population is largely unknown, but a small population of large sturgeon may be spawning annually below the hydropower dam on the St. Croix River (Atlantic Sturgeon Status Review Team 2007, see also discussion of Atlantic sturgeon above).

Marine Mammals

Marine mammals occurring in the vicinity of the proposed LNG terminal may be affected by vessel collisions and physical and acoustic harassment during construction and operation of the LNG terminal. Dolphins, seals, and porpoises are more likely than whales to be found in the area of the LNG terminal.

*Vessel Strikes*

During construction of the pier, there would be multiple vessels, tugs, barges, and lay vessels present in the Downeast LNG terminal area. These vessels would be required to operate in accordance with NOAA Fisheries regulations and requirements as discussed in section 4.6.2.1.

*Acoustic Harassment*

Sounds emitted during construction and operation of the LNG terminal would be classified as either pulsed or continuous sounds. Continuous sounds include those produced by construction vessels, tugs, barges, and lay vessels present in the Downeast LNG terminal area. The barges, which should be the largest vessel used during construction, would not produce engine noise because they would be towed by tugs. The tugs themselves would also increase the amount of underwater noise when they are towing the barges and positioning anchors. The intensity of noise tends to increase as the load that the tug pulls increases (Richardson et al. 1995). The marine mammals in the vicinity of the LNG terminal may habituate to low-level (Level B) underwater sounds and would accordingly be able to distinguish the sounds they generate for communication from those produced by human activities (Richardson et al. 1995). Downeast's adherence to restricted vessel speeds, both within the waterway for LNG marine traffic and in the LNG terminal area, would reduce the amount of noise emitted from vessel engines.

Downeast proposes to use drilled, rock socket pile installation that eliminates the need for blasting, therefore reducing noise impacts on local fauna. Downeast's analysis of acoustic impacts describes noise that ranges from 120 dB to 170 dB re 1 μPa for this type of continuous sound emission. No underwater blasting is expected to be required for installation of the terminal pier. Section 4.11.2 of this EIS discusses in greater detail the impacts of noise from construction and operation of the Downeast LNG Project.

NOAA Fisheries has identified measures that would be required to minimize underwater noise and ensure listed species under its jurisdiction would not likely be adversely affected by the Downeast LNG Project. Downeast has accepted these requirements and proposes to implement them, as listed below.

- Sound generated by impact pile driving in the wet would be mitigated by inserting wooden cushioning blocks between the hammer and pile, and by enclosing the pile(s) within a confined bubble curtain. Sound generated by vibratory pile driving would be mitigated by reducing power settings on the hammer, and by enclosing the pile(s) within a confined bubble curtain.

- In a filing with FERC on May 3, 2013, Downeast states that its current design could be constructed using only vibratory hammering, such that impact pile driving would not be required, and committed to using only vibratory hammering for pile driving.

- Downeast would model mitigated pile driving sound levels throughout the ensonified area and provide an updated isopleth map to NOAA Fisheries prior to the issuance of a concurrence letter.

- All pile installation, regardless of technique or equipment would conform to existing thresholds for Level A (i.e., sound pressure level of 180 dB RMS re: 1μPa) for injury to cetaceans, and Level B harassment (160 dB RMS re: 1μPa) for impulse noise and continuous sound (120 dB RMS re: 1μPa) as they pertain to listed marine mammals.

- Downeast would record PEAK sound pressure level and calculate Cumulative Sound Exposure Level (CSEL) and Root Mean Squared (RMS) from the SPL waveform and report results to NOAA Fisheries staff on a daily basis.

- During rock socket drilling and pile driving, Downeast would monitor sound pressure level (SPL) with hydrophones and a digital recorder capable of operating at a minimum of he hydrophone needs to operate at a minimum 30,000 samples per second for a minimum of one second, with an adjustable trigger level, and a range of at least 30 psi.

Based on protocol for measuring in-water acoustic fields and natural noise attenuation of 3-6 dB per doubling of distance, a minimum of three locations would be monitored, located approximately 10, 20, and 40 meters from the sound source.

- An acoustic monitoring plan (e.g., locations, personnel, and equipment) would be provided to Max Tritt at NOAA Fisheries at 17 Godfrey Drive, Suite 1, Orono, Maine 04473 or to max.tritt@noaa.gov at least 30 days prior to implementation.
- If any listed species are encountered in the action area, FERC and NOAA Fisheries Maine Field Station would be contacted immediately at (202) 502-6257 and (207) 866-3756, respectively.
- A post-project report, confirming completion of construction and the successful application of all terms and conditions of the permit, would be submitted to NOAA Fisheries and FERC within four weeks of project completion.
- Due to the water depth and vessel draft, the use of ship's bow thrusters would be prohibited during low tide when approaching/departing the pier or while docked.

The measures that Downeast would employ would minimize acoustic harassment impacts on all listed cetatean and sea turtle species. Downeast has committed to continue its consultation with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss appropriate mitigation measures. Upon completion of ESA consultation and federal and state permitting processes, Downeast would incorporate the final approved construction and mitigation measures into a comprehensive Prevention and Mitigation Manual for use in training of Downeast's construction and operational personnel, which would be filed with FERC.

*Pollution and Sediment Suspension*

Construction debris and human debris could potentially enter the marine environment. Downeast would provide environmental training to construction personnel that would give guidance on proper disposal requirements for debris and other refuse created during construction.

Increased sediment suspension and turbidity are expected to temporarily increase during construction of the pier. Increased suspended sediments may temporarily inhibit seals from foraging in or entering Mill Cove during construction. Marine mammals would experience increased turbidity in Passamaquoddy Bay; however, given that whale occurrence in this area is low, marine mammals are highly mobile, and that the duration of underwater construction is temporary, it is unlikely that marine mammals would be adversely affected by temporary increases in turbidity.

*Alteration of Prey Base*

Water withdrawals for hydrostatic testing, vessel engine cooling, vessel ballasting, vessel hoteling, and fire suppression pump testing would result in the entrainment of phytoplankton and zooplankton in the area surrounding the intake pipe or sea chest. Species that feed on phytoplankton and zooplankton (e.g., whales) would likely disperse from the area directly around the intake in search of food. Considering the minimal effect to phytoplankton and zooplankton from entrainment, the loss is expected to have a minimal impact on marine mammals as they search for prey in adjacent areas. Screens located on intake pipes and sea chest strainer plates would minimize entrainment of adult fish; however, juveniles may be subject to impingement. We believe any resulting loss would be minor and not likely in numbers to affect the prey base for marine mammals.

*Accidental Spills and Releases*

Impacts and mitigations associated with accidental spills and releases are similar to those described in section 4.6.2.1.

**State-Listed and Other Special Status Species**

Surveys of the land-based portion of the proposed LNG terminal were conducted by Downeast on July 12 to July 15, 2006. The survey focused on identifying particular natural communities and ecological conditions in which threatened, endangered, and rare species would likely occur and, when possible, to conduct specific field investigations for target species that could be observed. Threatened, endangered, and rare species were not identified during these surveys.

Bald Eagle

In a letter dated March 23, 2006, the FWS indicated that the bald eagle could occur within the vicinity of the proposed LNG terminal in Mill Cove. Information from Maine DIFW was reviewed for locations of historic and currently active eagle nests in the vicinity of the proposed LNG terminal. Aerial nest surveys were also conducted to augment the information provided by Maine DIFW. Although historic or active bald eagle nests were not observed in the vicinity of the proposed LNG terminal, the area associated with the LNG terminal contains habitat that may be used by transient individuals for foraging, loafing, and roosting. Downeast has agreed to conduct pre-construction clearance surveys for bald eagles. In the event that confirmed nesting bald eagles are discovered, Downeast would consult with Maine DIFW to establish a comprehensive bald eagle mitigation plan.

### 4.6.2.3 Sendout Pipeline

**Federally Listed Species**

Atlantic Salmon

The DPS comprises all naturally reproducing remnant populations of Atlantic salmon from the Kennebec River downstream of the former Edwards Dam site located in Augusta north to the mouth of the St. Croix River. In August 2006, Downeast LNG assessed fishery habitat using a technique recommended by the Maine ASC. At each stream crossing sampled, discrete habitat units were delineated on the basis of one or more physical characteristics that separated them from adjacent habitat types. Once a habitat unit was defined, appropriate attribute data were measured and recorded for the unit. These investigations indicated that for all but the St. Croix River and Magurrewock Stream outlet and the Wapsaconhagen Brook, there are no suitable spawning habitats for Atlantic salmon in the stream reaches crossed by the proposed sendout pipeline. For crossings at the St. Croix River and Magurrewock Stream outlet and the Wapsaconhagen Brook, spawning habitat of Atlantic salmon is likely based on the EFH description (NEFMC 1998) and the parameters measured in the field survey. Although conditions in some streams may be suitable for Atlantic salmon in various life stages, it is also important to note that few Atlantic salmon individuals are likely to be present in waters crossed by the sendout pipeline at any given time. Fay et al. (2006) notes that the wild St. Croix population of Atlantic salmon is considered extirpated, and that there is little to no natural reproduction within the St. Croix main stem and most of its tributaries. Despite stocking efforts, few returns are documented; and of those returns, many are of hatchery origin (Fay et al. 2006). In weir and fishway trap catches of Atlantic salmon in the St. Croix River, abundance has steadily declined from 1994 (181 captures) to 2004 (14 captures) (Fay et al. 2006). No mapped Atlantic salmon habitat occurs within the corridor of the Downeast pipeline route; however, there is undocumented salmon habitat downstream of the proposed crossing of the Wapsaconhagen Brook at MP 21.3 (located downstream of the proposed crossing in the Town of Woodland south of U.S. Route 1). Salmon presence was documented several years ago at this location, though current status is unknown. According to Dubé (pers. comm. 2008), this habitat is located well downstream of the proposed sendout pipeline crossing and would be adequately protected by the dam-and-pump dry crossing method proposed for this stream (see table 4.5.2.3-1).

In its February 1, 2008 letter to Downeast, the Maine DMR indicated that migrating Atlantic salmon may be present in the St. Croix River and Magurrewock Stream. Although Downeast indicated that no instream work would be conducted (see table 4.3.2.2-1), the Maine DMR requested additional information about the length of time Downeast expects the HDD of this crossing to be complete; information about noise or vibration caused by drilling activities; and requested that the HDD be conducted during the months of July and August. Similar concerns were raised by the FWS in its letter dated March 14, 2008. Downeast anticipates that the crossing would be complete in 75 to 90 days, where work would typically be conducted 24 hours per day. Downeast does not anticipate any disruption to surface water flows during this HDD and does not anticipate that blasting would be required. The tailings and mud from the drilling activity would be pumped into temporary storage tanks and hauled to an approved disposal site. Downeast has committed to implementing the FERC's Plan and Procedures as well as the *Maine Land and Water Quality Bureau's Erosion and Sediment Control Best Management Practices* to protect water quality and wildlife during construction and operation of the sendout pipeline.

Noise associated with HDD activities of the St. Croix River would be generated at the HDD entry point from diesel engines, which have sound mitigation devices installed. Vibration effects in the waterbody are expected to be minimal to absent because of the minimum vertical distance of 60 feet that would separate the bore shaft from the river bed. Downeast indicated that it continues to discuss with Maine DMR about construction schedules to avoid impacts on fisheries of interest, including Atlantic salmon. Downeast believes that a construction window of June through August would best avoid potential impacts on a suite of species, including Atlantic salmon, alewife, American shad, American eel, rainbow smelt, and blueback herring; however, it will continue to consult with Maine DMR about timing. Because the HDD would be timed to avoid critical life stage periods for Atlantic salmon present in the St. Croix River, direct impacts on this species caused by HDD are unlikely.

**State-Listed and Other Special Status Species**

<u>Bald Eagle</u>

Downeast reviewed information from Maine DIFW that identified the presence of several historic and active bald eagle nests in proximity to the proposed sendout pipeline (see section 4.6.1.2 for details on the bald eagle). Using this information as reference, aerial surveys were conducted on June 12, 2006 and again on May 5, 2008, in cooperation with Maine DIFW, to identify new and historic bald eagle nest sites. During the aerial surveys, no new eagle nests were observed within the study corridor or within the 0.25-mile zone on either side. Eagles were observed during the 2008 overflight but did not appear to be associated with nest sites within 0.25 mile of the sendout pipeline. Based on these surveys, active bald eagle nest sites would not be affected by construction of the sendout pipeline. A single historic nest was identified near MP 9.5; in this location, 1.7 acres of inactive nesting habitat would be affected during construction of the sendout pipeline. In addition, construction would affect eagle foraging and roosting/loafing habitats.

Construction activities that have the potential to disturb foraging bald eagles or known roosts are expected to be minimal, localized, and temporary. Prior to construction, locations of historic and active bald eagle nesting sites and buffer zones within the workspace would be surveyed and identified with signage as environmentally sensitive resources. To avoid and minimize adverse impacts on nesting bald eagles, Downeast has stated that construction activities would not occur within 0.25 mile of all identified bald eagle buffer areas between March 1 and August 31. To avoid disturbance to existing nests and the allocated 0.25-mile buffer, each portion of the proposed sendout pipeline that is near an active eagle nest would be reviewed for (a) minor rerouting; and/or (b) mitigation measures including seasonal prohibitions on construction. Downeast indicated it may also modify the timing of periodic inspections and/or repair of the sendout pipeline to ensure avoidance and minimization of disturbance during sensitive periods if a pipeline section occurs within the protected buffer of any active bald eagle nesting/breeding site.

In its March 14, 2008 letter, the FWS expressed concern about potential effects of noise and materials storage associated with the HDD operations proposed in the vicinity of the bald eagle nest located in the Moosehorn NWR at Magurrewock Marsh. Downeast indicated that the HDD site is located more than 0.5 mile away from the location of the bald eagle nest in question. While the drilling activity would produce noise, the drilling activities would be outside of the buffer area that the FWS suggests be implemented. Equipment and materials storage associated with the project would be located outside of the 0.25-mile buffer around the eagle nest site.

Construction and operation of the proposed Downeast LNG Project is not anticipated to cause adverse impacts on bald eagle prey species (e.g., sculpin, eel, common eider). A significant reduction in anticipated affected habitat of the bald eagle was made by modifying the sendout pipeline route. Downeast continues to coordinate with the FWS and Maine DIFW regarding preferred avoidance and minimization for this species.

Downeast has stated that the sendout pipeline corridor would be resurveyed prior to the commencement of construction activities to detect the presence of federal- or state-listed species. Downeast would coordinate any necessary mitigation with FWS, Maine NAP, and Maine DIFW.

### 4.6.3 Conclusions and Recommendations for Threatened, Endangered, and Other Special Status Species

**Effects on Whales and Sea Turtles**

The proposed Downeast LNG Project has the potential to adversely affect the leatherback sea turtle and each of the six whale species identified within the project area, either by acoustic take or whale-vessel (or turtle-vessel) strikes. Federally designated critical habitat does not occur within the proposed project area, and thus would not be affected by the proposed action. The full extent to which long-term low-level anthropogenic sound impacts marine mammals and sea turtles is not well understood. However, adverse acoustic impacts during pile driving would be mitigated through Downeast's use of a vibratory hammer and engagement of a NOAA Fisheries approved mammal and marine spotter to ensure no listed species are within the designated NOAA Fisheries Acoustic Safety Zone during this activity. The density of whales and leatherback sea turtles in the proposed transit route, combined with the proposed increase in vessel traffic resulting from delivery of LNG to Robbinston, Maine, increases the potential for vessel-whale encounters to occur. Any injury or fatality that results from a whale-vessel (or turtle-vessel) encounter would be an adverse effect. To mitigate for this adverse effect, LNG vessels would adhere to NOAA Fisheries regulations to reduce the threat of vessel strikes.

Based on the mitigative measures that Downeast has proposed for the North Atlantic right whale, which would also act to mitigate impacts on other cetaceans and the leatherback sea turtle, we believe that construction and operation of the proposed Downeast LNG Project is *not likely to adversely affect*, leatherback sea turtles, blue, fin, humpback, North Atlantic, sei, or sperm whales. More specific information about impacts and mitigations are discussed in the BA (see Appendix C).

**Effects on Atlantic Salmon**

The proposed project has the potential to adversely affect Atlantic salmon; however, Downeast has agreed to implement a variety of mitigation measures that would minimize or avoid impacts on this species. These mitigative measures include timing construction to avoid times of year when migrating salmon smolts or adult salmon are likely to be present; employing construction methods in stream crossings that are least damaging to the aquatic habitat; and preserving and restoring riparian buffers. Implementation of these measures would be sufficient to prevent adverse impacts on Atlantic salmon. Construction and operation of the proposed project *is not likely to adversely affect* Atlantic salmon.

**Effects on Atlantic and Shortnose Sturgeon**

The proposed project has the potential to adversely affect Atlantic sturgeon and shortnose sturgeon; however, Downeast has agreed to implement a variety of mitigation measures that would avoid or minimize impacts on these species. These mitigation measures include timing construction to avoid times of year when migrating sturgeon are likely to be present and implementing construction methods that preserve habitat (e.g., use of HDD). Construction and operation of the proposed project *is not likely to adversely affect* Atlantic sturgeon and shortnose sturgeon.

## 4.7 LAND USE, RECREATION, AND VISUAL RESOURCES

The Downeast LNG Project would be located in Washington County, Maine. The proposed LNG terminal would be located on 80 acres of privately owned land located between U.S. Route 1 and Passamaquoddy Bay in Robbinston, Maine. Downeast holds an option to purchase the entire land parcel. The site would be located on the south side of Mill Cove, south of the confluence of the Passamaquoddy Bay and St. Croix River between the larger towns of Eastport, Perry, and Calais, Maine. The proposed pier would extend 3,862 feet northeast from the terminal site and would be located on Maine public submerged lands.

Downeast proposes to construct and operate a 29.8-mile-long, 30-inch-diameter natural gas sendout pipeline, which would extend from the LNG terminal to the existing M&NE pipeline system at the Baileyville Compressor Station in Baileyville, Maine. About 12 miles (40 percent total) of the sendout pipeline from MP 17.7 to MP 27.2 and MP 27.3 to MP 29.8 would be immediately adjacent to the existing EMEC electric transmission line right-of-way (32 percent) and the existing M&NE pipeline right-of-way (8 percent). ATV trails would parallel the sendout pipeline from MP 0.7 to MP 3.7 and MP 21.6 to MP 28.3. Additionally, it is anticipated that the nonjurisdictional EMEC transmission line right-of-way would be collocated with approximately 11.4 miles (38 percent) of the sendout pipeline between MP 0.2 and MP 11.6. See section 2.9 of this EIS for further information on nonjurisdictional facilities.

### 4.7.1 Land Use

Most of the land affected by construction and operation of the Downeast LNG Project would be forest land at the LNG terminal and along the sendout pipeline. Other land uses affected by the project would be submerged lands, developed land, agricultural land and grassland. Construction would affect a total of 313.2 acres of land, 55 acres for the LNG terminal and laydown areas, 3.6 acres for the pier, 201.3 acres for the pipeline, 0.8 acre for the valve station and pigging and metering facilities, 10.1 acres for access roads, 23.7 acres for off-site pipe laydown and storage areas, and 18.7 acres for ATWS, including HDD ATWS. Operation of the project would affect 188.8 acres of land, of which 50.6 acres would be permanently converted for operation of the terminal facilities, and the remaining 138.2 acres would be maintained as permanent right-of-way for the sendout pipeline, valve station, pig receiving facility, and access roads. Table 4.7.1-1 summarizes the acres of each land use category that would be affected by construction and operation of the proposed project.

#### 4.7.1.1 Waterway for LNG Marine Traffic

The marine traffic route would consist of passage through the Bay of Fundy to Head Harbour Passage, to Western Passage, to Passamaquoddy Bay to the LNG terminal. The LNG vessels would enter the Head Harbour Passage approximately 1.5 miles from Quoddy Head at the northern end of Campobello Island. From the entry point, the LNG vessels would travel 16.6 nautical miles along 13 different legs to the LNG terminal. The longest leg of the passage is in Passamaquoddy Bay, which follows the United States and Canadian border. Additional details on the marine traffic route are included in sections 2.1.1 and 4.12 of this EIS.

TABLE 4.7.1-1

**Acres of Land Affected by Construction and Operation of the Proposed Downeast LNG Project**

| Facility | Forest Land | | Developed Land | | Agricultural Land | | Grassland | | Submerged Land | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Con.** | **Op.** | **Con.** | **Op.** | **Con.** | **Op.** | **Con.** | **Op.** | **Con.** | **Op.** | **Con.** | **Op.** |
| LNG Terminal a/ | 47.0 | 47.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 47.0 | 47.0 |
| Off-site laydown areas | 0 | 0 | 3.0 | 0 | 0 | 0 | 5.0 | 0 | 0 | 0 | 8.0 | 0 |
| Pier | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3.6 | 3.6 | 3.6 | 3.6 |
| **Subtotal LNG Terminal** | **47** | **47** | **3.0** | **0** | **0** | **0** | **5.0** | **0** | **3.6** | **3.6** | **58.6** | **50.6** |
| 30-inch-diameter Sendout Pipeline b/, c/ | 173.0 | 110.5 | 14.2 | 8.4 | 1.8 | 1.1 | 12.3 | 7.6 | 0 | 0 | 201.3 | 127.6 |
| Off-site pipe laydown and storage areas | 22.1 | 0 | 0.9 | 0 | 0.7 | 0 | 0 | 0 | 0 | 0 | 23.7 | 0 |
| Valve Station (MP 17.17) | 0.3 | 0.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.3 | 0.3 |
| Pig Receiving and Gas Metering Facility at Baileyville Terminus (MP 29.8) d/ | 0 | 0 | 0.5 | 0.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0.5 | 0.3 |
| Additional Temporary Workspace and HDD Additional Temporary Workspace | 13.7 | 0 | 2.4 | 0 | 1.6 | 0 | 1.0 | 0 | 0 | 0 | 18.7 | 0 |
| Access Roads e/ | 0.6 | 0.5 | 9.5 | 9.5 | 0 | 0 | 0 | 0 | 0 | 0 | 10.1 | 10.0 |
| **Subtotal Sendout Pipeline** | **209.7** | **111.3** | **27.5** | **18.2** | **4.1** | **1.1** | **13.3** | **7.6** | **0.0** | **0.0** | **254.6** | **138.2** |
| **Project Total** | **256.7** | **158.3** | **30.5** | **18.2** | **4.1** | **1.1** | **18.3** | **7.6** | **3.6** | **3.6** | **313.2** | **188.8** |

a/ Includes the pig launching facility inside the terminal property.
b/ Includes nominal 75-foot-wide construction right-of-way and a 50-foot-wide operation right-of-way.
c/ This table only shows the land that actually would be physically disturbed by the terminal and pipeline construction and operation. Areas where HDD is being proposed, including under the St. Croix River, are excluded because these areas would not be disturbed by construction or operation of the pipeline facilities.
d/ Pigging facilities at the Baileyville Compressor Station would be constructed in previously disturbed areas within the station property.
e/ Only the access road at MP 15.4 would require clearing for a new road base. The other three temporary access roads have existing road bases; however, they would need to be upgraded prior to construction of the sendout pipeline and would not be restored to pre-existing conditions.

### 4.7.1.2 LNG Terminal

The LNG terminal would consist of an onshore LNG terminal and an offshore pier. The northern portion of the site once contained a homestead and farmland up until the 1960s. Currently, there are no residences located on the parcel. Some of the former agricultural fields remain relatively open, although they are reverting to wooded uplands and forested/scrub-shrub wetlands. Scattered household wastes, remnant fencing, and apple trees are the only remaining evidence of the former homestead. The remainder of the site consists of wooded uplands and two wetlands. Of the 80 acres, 68 acres are classified as forest land and 12 acres are classified as wetlands (FWS 1998; Maine Office of GIS 2006b; Woodlot 2005). Both the uplands and wetlands have been historically harvested, with the most recent harvesting occurring in the mid 1990's (Krug 2005). Harvesting over much of the site was intensive and numerous remnant skidder trails are evident. There are also several large slash piles, particularly on the southern side of the site associated with a former log landing (Woodlot 2005).

Land use impacts associated with the LNG terminal would include temporary disturbance of 58.6 acres of existing land uses during construction of new permanent facilities and pier. About 50.6 acres of the terminal site would be affected by operation of the LNG terminal (47.0 acres of forest land, and 3.6 acres of submerged land for the pier). The remaining portion of the 80-acre parcel would be left undeveloped. Three off-site areas would be used for terminal equipment and pipeline laydown, temporarily disturbing 8.0 acres of developed land and grassland during construction.

The 3,862-foot-long pier would be constructed over the Passamaquoddy Bay submerged lands. The pier would have a surface area of 3.6 acres, mostly over open water. Only 0.1 acre of the submerged land would be directly affected by the footing of the pilings. Construction of the pier abutment would necessitate the removal of rock ledge within the regulated coastal zone. Pier construction would require a lease or easement from the State of Maine for activities conducted on submerged land. Maine defines submerged lands as all coastal land (including islands) from the mean low-water mark out to the 3-mile territorial limit. Where intertidal flats are extensive, the shoreward boundary begins 1,650 feet seaward from the mean high-water mark. Structures located on submerged land require a lease or easement when the existing use is being changed or the size of an existing structure is being changed. Leases or easements are also required for pipelines, utility cables, outfall/intake pipes, and dredging. Downeast will submit its Submerged Lands Lease application to the Maine Department of Conservation, Bureau of Parks and Land, in conjunction with its Maine DEP permit, after issuance of the final EIS. In its comments on the draft EIS, the Bureau of Parks and Land stated that impacts of the security zone around the facility as well as the moving security zone for LNG vessels will be a primary concern raised by recreational boaters, other waterway users, and those promoting public access and eco-tourism during its review of the submerged lands lease application. The Bureau of Parks and Land also recommended that Downeast explore options for allowing small watercraft to transit under the pier in order to maintain near-shore navigation options. It would be up to the Coast Guard COTP, under the authority of the Ports and Waterways Safety Act, to determine whether to allow small watercraft into the 500-yard, fixed safety/security zone around the moored LNG vessel, which would include a portion of the pier.

The COE, New England District, has published guidelines for the placement of fixed and floating structures in navigable waters of the United States that are regulated by the New

England District (COE 1996). The guidelines were developed to provide common sense guidance for structures in navigable waters. The guidelines suggest that no structures built on a linear waterway should extend more than 25 percent of the waterway width at mean low water. The 3,862-foot pier design as proposed by Downeast appears to extend just over 25 percent of the width of the St. Croix River/Passamaquoddy Bay at the project location. However, it is difficult to assign an exact percentage because of the irregular shoreline on both the United States and Canadian sides of the waterway near the project location. The guidelines do not constitute policy or regulation, and in themselves are not enforceable. However, as suggested by the COE, they provide guidance for project design that typically would not generate adverse public comment or result in permit denial. In its review of the Section 10 permit for the project, the COE will take into consideration how much of the linear waterway would remain open, in addition to obtaining feedback from the Coast Guard, pilots, and harbormasters, and would determine if the proposed pier is acceptable for the site-specific conditions. In addition, we have evaluated alternative pier designs in section 3.5 of this EIS, two of which would include a shorter pier that would meet this guideline.

#### 4.7.1.3 Sendout Pipeline

The valve station would be located at MP 17.17 in Baring and would affect 0.3 acre of forest land outside the pipeline construction right-of-way during construction. Of this area, 0.3 acre would be maintained for operation of the valve station. The pig launching facility would be located on the LNG terminal property. Land use impacts from the construction and operation of this facility are included in table 4.7.1-1. The pig receiving and gas metering facility would be located at MP 29.8 in Baileyville and would affect 0.5 acre of developed land during construction and 0.3 acre of developed land during operation.

Most of the land affected by the construction and operation of the sendout pipeline would be forest land (20.7 miles or 69.6 percent). Other land uses affected along the sendout pipeline would include open water (e.g., St. Croix River) (0.3 mile or 1.1 percent), developed land (2.0 miles or 6.6 percent), agricultural land (0.9 mile or 2.9 percent), wetlands (forested, herbaceous, and scrub-shrub) (5.7 miles or 19.1 percent), and grassland (0.2 mile or 0.7 percent). Construction of the sendout pipeline would affect a total of 254.6 acres of land, 201.3 acres for the pipeline construction right-of-way, 0.3 acre for the valve station, 0.5 acre for the pig receiving facility, 10.1 acres for access roads, 23.7 acres for off-site pipe laydown and storage areas, and 18.7 acres for temporary workspace areas and staging areas. Operation of the sendout pipeline would affect a total of 138.2 acres of land, of which 127.6 acres would be permanently converted to maintain the sendout pipeline, 0.3 acre for operation of the valve station, 0.3 acre for the pig receiving facility, and 10 acres for access roads.

We received a comment from the Maine Bureau of Parks and Lands, Submerged Lands Program, advising that a Submerged Lands Lease would be required for the portion of sendout pipeline to be drilled under the St. Croix River. This lease has been added to table 1.3-1, Major Permits, Approvals, and Consultations for the Downeast LNG Project.

It is anticipated that the new nonjurisdictional EMEC electric transmission line would parallel approximately 11.4 miles (38 percent) of the sendout pipeline from MP 0.2 to MP 11.6. Additionally, ATV trails would parallel the sendout pipeline from MP 0.7 to MP 3.7 and MP 21.6 to MP 28.3 for a total of about 9.55 miles. Approximately 12.0 miles (40 percent) of the pipeline would be installed in or adjacent to other existing utility or road rights-of-way between

MP 17.7 and MP 27.2 and MP 27.3 and MP 29.8. Downeast is currently coordinating with EMEC on the use of their existing transmission line right-of-way for a portion of the pipeline right-of-way. If feasible, where the pipeline would be directly adjacent to EMEC's existing right-of-way, the new pipeline would be offset about 5 to 10 feet from the outside edge of the existing right-of-way. The 50-foot-wide permanent pipeline right-of-way as well as a portion of the construction right-of-way, would partially overlap the existing electric transmission line right-of-way. If this is agreed upon, approximately 15.7 acres of the sendout pipeline construction right-of-way and 2.2 acres of the permanent right-of-way would overlap the EMEC transmission line right-of-way. See sections 2.2.2.1 and 2.9 for further discussion of the existing transmission line and proposed nonjurisdictional facility.

The sendout pipeline centerline would be offset from the M&NE pipeline right-of-way by approximately 50 feet between MP 27.35 and MP 29.8. Approximately 5.9 acres of the M&NE right-of-way would be utilized for the sendout pipeline construction right-of-way and pipeline laydown areas and ATWS. None of the sendout pipeline permanent right-of-way would overlap the M&NE pipeline right-of-way.

Land use impacts associated with the sendout pipeline would include temporary disturbance of existing land uses within construction work areas along the right-of-way during construction and creation of new permanent right-of-way for operation and maintenance of the pipeline. Downeast generally would use a 75-foot-wide construction right-of-way to fabricate and install the 30-inch-diameter pipeline. Following construction, a 50-foot-wide permanent right-of-way would be maintained in an herbaceous/shrub state during operation of the sendout pipeline. A 55-foot-wide construction right-of-way would be used where the proposed route crosses residential areas and in several wetlands. Following construction in these areas, a 30-foot-wide permanent right-of-way would be maintained in an herbaceous/shrub state during operation of the sendout pipeline.

Construction of the sendout pipeline, valve station, and pig receiving facility would affect a total of 254.6 acres, of which 138.2 acres would be maintained as permanent right-of-way following construction. About 111 acres of forest land, including forested wetlands, would be permanently converted to industrial use for operation of the sendout pipeline and valve station. Disturbance to forest land would be minimized by locating the majority of the sendout pipeline right-of-way adjacent to existing maintained utility rights-of-way and ATV trails. Other land uses affected permanently along the sendout pipeline right-of-way would include developed land (18.2 acres), agricultural land (1.1 acres), and grassland (7.6 acres). Land that would be retained as permanent right-of-way for the sendout pipeline would be allowed to revert to former use with certain restrictions. Following construction, the temporary right-of-way and additional work areas would be reverted to their previous land use.

Pipeline construction would require the use of extra workspace areas and staging areas, which would be short-term and temporary. There are 146 potential staging areas that have been identified along the proposed sendout pipeline route. Table 2.2.2.1-1 lists the location and land use for each additional temporary workspace. The combined total approximate acreage of the staging areas is 50.2 acres. These staging areas would be restored to their pre-construction conditions upon completion of construction.

### 4.7.2 Existing and Planned Residences and Structures

#### 4.7.2.1 Waterway for LNG Marine Traffic

There are concentrated developments in a few locations along the marine traffic route such as Eastport, Maine and St. Andrews, New Brunswick. Eastport is located southeast of the LNG terminal, and along Friar Roads where the LNG vessels would turn northwest between Eastport, Maine and Indian Island, New Brunswick. St. Andrews is a Canadian resort town located opposite the LNG terminal. A more detailed discussion of populated areas and population density along the waterway for LNG marine traffic route is discussed in section 4.8.1.

The waterway for LNG marine traffic would pass by developed areas in Eastport, Maine and St. Andrews, New Brunswick, and scattered seasonal and permanent residences along the route. The impact on these areas during normal operation is primarily a visual impact, which is discussed in section 4.7.4.

#### 4.7.2.2 LNG Terminal

No existing or planned residences or structures are within 50 feet of the proposed LNG terminal. Several residential properties are located to the south and west of the site generally along U.S. Route 1. The nearest residences to the proposed LNG terminal are located along U.S. Route 1 across from the LNG terminal site. The closest residence is located approximately 125 feet from the LNG terminal site entrance. To the south, there are a few residences located 1,500 feet or more from U.S. Route 1 moving toward the shoreline. These residences are located over 2,000 feet from the project site. To the northwest, there is a cluster of residential properties along Ridge Road near the intersection of U.S. Route 1. There is also a local utility station and small retail store in this area. North of the site, several residential properties are located along U.S. Route 1, along with other properties including a church (approximately 0.6 mile from the LNG terminal site entrance), elementary school (approximately 0.8 mile from the LNG terminal site entrance), and fire station (approximately 0.8 mile from the LNG terminal site entrance). There are also several waterfront homes located on Passamaquoddy Bay northeast of the site.

Residents in proximity to the LNG terminal site may experience temporary effects associated with construction and permanent effects associated with operation of the LNG terminal. Temporary impacts due to construction include noise and dust from construction equipment, particularly pile-driving equipment. Because of the temporary nature of noise from vibratory and impact pile driving, no adverse or long-term effects are anticipated. Noise from other construction activity may be noticeable at nearby residences, especially during periods of extensive earthwork using heavy equipment. Local traffic during the construction phase is also expected to increase, along with associated vehicle noise. Potential adverse effects associated with construction and operational noise are discussed further in section 4.11.2 of this EIS.

Given the distance between proposed construction activity and the nearest residences noted above and the proposed dust control measures, impact on residences from dust generated during construction would not be significant.

During operation of the proposed LNG terminal, the primary impact on those residences discussed above would be visual. The LNG storage tanks would be about 160 feet tall and the pier would be 3,862 feet long; both would be visible from the Mill Cove area. See section 4.7.4 for further information on visual resources.

### 4.7.2.3 Sendout Pipeline

The draft EIS described 19 residences that would be within 50 feet of the permanent right-of-way. Downeast subsequently revised its pipeline route and work areas to increase the distance between the residences and construction work areas. There are now two residences located approximately 50 feet from the construction right-of-way. Table 4.7.2.3-1 shows the locations of these residences and distance from the construction right-of-way and the pipeline centerline. Appendix P includes the revised site-specific residential construction plans for all 19 residences.

TABLE 4.7.2.3-1

**Residences within 50 Feet of the Construction Right-of-way for the Proposed Downeast Sendout Pipeline**

| Milepost | Number of Residences | Distance from Construction ROW (feet) | Distance from Pipeline Centerline (feet) |
|---|---|---|---|
| 0.63 | 1 | 54 | 74 |
| 0.91 | 1 | >50 | 31 |

Based on Downeast's communications with town managers and real estate professionals, neither Robbinston nor the surrounding communities are planning to construct or have been notified of planned residential or commercial/business developments or subdivisions that would be crossed or within 0.25 mile of the sendout pipeline (Howard 2006a; Porter 2006; Moholland 2006).

In a letter filed March 17, 2008, Ms. King expressed concerns with the proposed pipeline route that would pass through the community of Baring Plantation and near her residence. The King residence is located at approximately MP 16.9. The nearest proposed workspace is more than 95 feet from the residence. Downeast has not prepared a site-specific plan for this residence because it is more than 50 feet from the construction workspace. Ms. King disputed that location in a subsequent letter dated May 19, 2008, and we have determined that the house is located more precisely between MP 16.9 and MP 17.0; this does not alter the distance between the workspace and the residence. Ms. King also identified a potential route variation in this area which is discussed in section 3.8.2.1 of this EIS.

Between MP 16.2 and MP 16.4, there is a residential townhouse complex that has been developed and may be expanded. At its closest point, the townhouse complex is 80 feet from the pipeline right-of-way. There are no ATWS areas within 50 feet of this complex. According to Downeast, the routing of the pipeline has been coordinated with the landowner to avoid future development plans.

In residential areas, the two most significant impacts associated with construction and operation of natural gas pipelines are disturbance during construction and encumbrance of property for future uses (e.g., the limitation on future permanent structures within the permanent pipeline right-of-way). Residences within 50 feet of construction work areas are considered to be the most likely to experience the effects of pipeline construction. Temporary construction impacts on residential areas could include inconvenience caused by noise and dust generated by construction equipment; trenching through roads or driveways; ground disturbance of lawns; removal of landscaping or natural vegetative screening; potential damage to existing septic systems or wells; and removal of aboveground structures, such as sheds or trailers, from within the right-of-way.

Downeast filed site-specific plans for residences within 50 feet of the permanent right-of-way (see Appendix P). In October 2009, Downeast filed modified site-specific plans, and subsequently revised those plans in January 2010. The January 2010 plans are included in Appendix P in this EIS. We have not received any landowner comments about these plans. These site-specific plans include a number of standard construction practices such as the installation of a safety fence along the edge of the permanent right-of-way out to a distance of 100 feet on either side of the residence; preparing access and establishing environmental protection devices in accordance with BMPs; immediate restoration of driveway, lawn areas, and landscaping within construction work areas, except where required for continued construction access; and immediate restoration of all remaining areas following final restoration. In addition, Downeast previously stated that it would provide site-specific plans for residences within 50 feet of construction work areas and that the plans would include such safety measures as the installation of a safety fence along the construction right-of-way boundary to restrict public access in the work area; preserving mature trees and landscaping where possible while maintaining construction safety; welding, inspecting, and installing pipe as rapidly as possible to minimize construction time in residential areas; limiting active work hours; and backfilling the trench as soon as the pipe is laid or placing steel plates and/or mats in areas where the trench must remain open overnight. Section 3.8.2 of this EIS describes pipeline route variations Downeast incorporated into its proposed route to minimize impacts on the residences within 50 feet of the permanent right-of-way. Section 3.8.2 includes a table comparing the impacts of the proposed route (without the route variations) and the proposed route with the route variations. We believe these route variations would minimize impacts on these residences.

Downeast would obtain an easement from the landowner in order to construct the sendout pipeline. An easement would be used to convey both temporary (for construction) and permanent (for operation and maintenance) rights-of-way to Downeast. The easement would give Downeast the right to construct, operate, and maintain the sendout pipeline, and establish a permanent right-of-way. In return, Downeast would compensate the landowner for use of the land. The easement agreement between the company and the landowner typically specifies compensation for the loss of use during construction, loss of nonrenewable or other resources, and allowable uses and restrictions on the permanent right-of-way after construction. These restrictions can include prohibition of construction of aboveground structures, including house additions, garages, patios, pools, or any other object not easily removable; roads or driveways over the sendout pipeline; or the planting and cultivating of trees or orchards within the permanent easement. The areas used as temporary construction right-of-way and temporary extra workspace would be allowed to revert to pre-construction uses with no restrictions.

The acquisition of an easement is a negotiable process that would be carried out between Downeast and individual landowners. If the necessary land cannot be obtained through good faith negotiations with property owners and the project has been certificated by the Commission, Downeast may use the right of eminent domain granted under Section 7(h) of the NGA and the Federal Rules of Civil Procedure (Rule 71A) to obtain easements. Downeast would still be required to compensate the landowner for the right-of-way and damages incurred during construction; however, according to state or federal law, a court would determine the level of compensation.

### 4.7.3 Existing Public, Recreation, and Special Land Uses

#### 4.7.3.1 Waterway for LNG Marine Traffic

The waterway for LNG marine traffic follows two different routes from entering the Bay of Fundy to Quoddy Head. The route chosen by the LNG vessel captain would be determined in consultation with pilots, Transport Canada, and COTP and would depend on visibility, wind, tide cycle, and other such constraints. The eastern route follows an established navigational route that was modified in 2003 to reduce the likelihood of vessel strikes of whales. However, this route most likely would be used when the chance of encountering whales is low (see Appendix F, figure F-1). Lobster fishing is seasonal on this route (from the second Tuesday in November to January 15 and April 15 to June 30). There is no fishing from June 30 through November. Commercial shipping traffic occurs on this route, and according to Downeast, there is very little recreational traffic on this route from June through September. There are approximately 60 passenger ships and approximately three right whale tour boats along the eastern route. However, the whale boat tours generally do not operate in the designated shipping channel east of Grand Manan Island.

Year round and seasonal ferry passenger ships and small car ferries transit this area. The Princess of Acadia ferry travels between St. John, New Brunswick and Digby, Nova Scotia on a year round schedule, with more frequent trips between May and October. A conventional ferry and a high-speed ferry travel between Bar Harbor and Portland, Maine and Yarmouth, Nova Scotia from May to October. There is a daily ferry departing from Blacks Harbour, New Brunswick, to North Head, Grand Manan, with a connecting ferry to White Head Island. The Deer Island Princess and the John E. Rigby ferries travel year round in Passamaquoddy Bay. The waterway is a known navigation route and should have minimal impact on recreational and commercial users.

While no mandatory deep draft vessel routing is currently prescribed, during other times of the year, the LNG vessels most likely would use the route to the west of Grand Manan (see Appendix F, figure F-1), which does not have a designated shipping lane. Although there is less of a chance of encountering whales using the western route, the vessel would encounter more commercial fishing and possibly recreational activities along this route. Downeast consulted with local fishermen and found that, generally, the fishermen try to avoid placing their gear in designated shipping lanes in order to prevent loss of their equipment. Because there is no designated shipping lane along the western route, it is likely that more fishing gear may be encountered. Downeast stated that in hearings conducted by the Maine BEP, fishermen stated that they do not have a problem with LNG vessels being able to transit the area to the LNG terminal. However, they did indicate that a specific transit routing on the western route, for both existing traffic and LNG vessels, would assist fishermen in avoiding the placement of traps in the way of commercial vessels. On this route, lobster fishing takes place from June 1 to November 30. Additionally, Downeast consulted with Fundy Traffic and found that most passenger ships and whale boat tours do not transit this route; however, seasonal ferries do use this route.

From Quoddy Head, the route would traverse Head Harbour, Western Passage, and Passamaquoddy Bay to Mill Cove. Recreational boating occurs in the Western Passage and Passamaquoddy Bay and includes whale-watching tours in Passamaquoddy Bay, which typically occur between May and October. Downeast contacted the Quoddy Pilots Association, which stated that recreational boating activity is light in the Western Passage (Peacock 2006).

Recreational fishing is light in Passamaquoddy Bay, and activities include lobstering, scalloping, and fin fishing. Shellfishing is considered an important recreational resource in Passamaquoddy Bay. Observations taken by Downeast from 2004 through 2006 indicate that recreational activity is extremely limited, most likely because of the large extent of the intertidal area exposed at low-water and the strong tidal currents. According to Downeast, local harbor pilots (Peacock 2006) confirmed the limited use of the area, as well as several field surveys taken during trips with the Quoddy Pilots Association during the summers of 2005 and 2006. However, during the tourist season (late spring, summer, and early fall), recreational boating and fishing could see an increase. The City of Eastport, St. Andrews, New Brunswick, and other municipalities along the shoreline are exploring eco-tourism as a source of income and employment. Eco-tourism activities could include kayaking, recreational fishing, canoeing, sightseeing, and whale watching.

Eight state-owned parcels would be along the waterway for LNG marine traffic route. These include Gleason Point Park, Frost Island, an unnamed island in Perry, Carlow Island/Moose Island Scenic Area, Shackford Head State Park, Sumac Island, an unnamed island in Eastport, and Quoddy Head State Park in Lubec (see Appendix F, figure F-31 and F-32). No federal parks are located along the transit route. The southern portion of Roosevelt Campobello International Park, approximately 335 acres, is along the waterway. Liberty Point is the largest vehicle parking area in the Roosevelt Campobello International Park's Natural Area. At this location, there are two decks for observation of scenic vistas, marine mammals, and birds. Liberty Point is a popular hiking area and is the beginning of hiking trails that parallel the shore to Lower Duck Pond and to Raccoon Beach.

Table 4.7.3.1-1 lists the parks and state-owned lands that are along the waterway for LNG marine traffic.

TABLE 4.7.3.1-1

**Parks and State-Owned Land Along the Waterway for LNG Marine Traffic**

| Parcel Name | Town | Total Area (acres) |
|---|---|---|
| Roosevelt Campobello International Park | New Brunswick | 335 |
| Gleason Point Park | Perry | 32 |
| Frost Island and Unnamed Island | Perry | 1.6 |
| Carlow Island and Moose Island Scenic Area | Eastport | 31 |
| Shackford Head State Park | Eastport | 90 |
| Unnamed Island | Eastport | 0.8 |
| Sumac Island | Eastport | 1 |
| Quoddy Head State Park and West Quoddy Lighthouse | Lubec | 524 |

We received comments during the scoping period regarding project impacts on in-stream tidal power projects in the towns of Eastport, Lubec, and Perry, Maine. Several renewable energy tidal power projects are proposed in the general project area, located in Passamaquoddy Bay and Cobscook Bay. Preliminary permits were issued for the following tidal energy projects by the Secretary of FERC: Ocean Renewable Power Company's Western Passage Tidal Energy Project

(FERC Docket No. P-12680), Tidewalker Associates' Half-Moon Cove Tidal Power Project (FERC Docket No. P-12704), and the Passamaquoddy Tribe's Pleasant Point/Western Passage Tidal Energy Project (FERC Docket No. P-12710) and Cobscook Bay Tidal Project (FERC Docket No. P-12711). The Pleasant Point/Western Passage permit was terminated on May 27, 2010 at the request of the Passamaquoddy Tribe. We are aware of only one of the tidal projects that has advanced; Ocean Renewable Power Company placed its first prototype turbine generator unit online in September 2012, and will evaluate production for about three years to determine the potential for large scale power production.

These projects would consist of underwater turbines positioned within the water column and anchored to the bay/ocean bottom. Based on public information provided by the tidal energy companies, the top of the turbine units would be below the maximum depth of any commercial vessel transiting during low tide. Since the LNG vessels would be transiting the Western Passage at slack high tide, the turbines would be considerably below the LNG vessel hull.

We also received comments during the scoping period from Huntsman Marine Science Center (HMSC), a not-for-profit research and teaching facility located in St. Andrews, New Brunswick, regarding access to the Western Passage for education programs. A new aquarium was opened on the HMSC campus in 2011, which adds to the year round attraction of the campus to tourists and researchers. A key component of the HMSC's education programs is trawling for invertebrates and fish within the Western Passage. This area is rich in marine life, and is easily and cost-effectively accessible to their vessels. If HMSC is excluded from this area for operational or security reasons associated with the LNG facility, they feel it would negatively impact the quality of their programs and greatly increase the cost and time commitments of their clients as they would have to undertake much longer trips to alternate sites.

Similarly, HMSC's operations depend on the maintenance of a healthy marine environment within the region. Should the operations of the LNG facility drive away marine mammals, sea birds, marine fishes, and tourists, it would directly and negatively impact their activities and viability.

Operation of the project facilities would impact recreational boating, fishing, and sightseeing, and possibly restrict HMSC research vessels throughout the LNG vessel transit route as a result of the moving safety/security zones around the LNG vessels. Downeast estimates that an LNG vessel would arrive once every five to seven days in the winter, and once every eight to ten days in the summer. Currently there are other terminals in the area that accommodate both industrial and commercial vessels, including vessels associated with the Bayside terminal to the north of the proposed LNG project on the St. Croix River. As a result, marine traffic associated with the project would not introduce any significant new type of impacts on recreational boating or fishing. However, as part of its WSR, the Coast Guard has recommended that comprehensive safety and security zones be established around LNG vessels during transit up Head Harbour Passage, Western Passage, and Passamaquoddy Bay for the protection of the LNG vessels, alternate waterway users, and area residents. This is discussed further in section 4.12. The WSR recommends a moving safety/security zone for Passamaquoddy Bay of 2.0 nautical miles ahead, 1.0 nautical mile astern, and 0.25 nautical mile abeam of the vessel.

The moving safety zone is enforced around each LNG vessel as it proceeds along the marine traffic route, and the moored vessel security zone is enforced around the vessel unloading facility while a vessel is docked. This could cause impacts on recreational boating, fishing, sightseeing, and HMSC research vessels, but the impacts would be temporary while the vessel is in transit or moored at the vessel unloading facility. Because the safety zone would move with the vessel, the impacts would be of short duration at any given point along the shipping route. In most cases there will be ample room for boaters to freely navigate the waterway along the outer periphery of the channel and ahead and astern of any LNG vessel present. Many recreational boats should be able to go around the LNG vessels at points in the marine traffic route that are sufficiently wide for them to be outside of the safety zone. In locations where the waterway is narrow, boaters attempting to travel in the opposite direction of an LNG vessel traveling at 10 knots may need to wait up to 18 minutes for the LNG vessel to pass before proceeding on its way. The delay would increase up to 36 minutes when the LNG vessel is traveling at 5 knots and up to 60 minutes when the LNG vessel is traveling at 3 knots. For boaters near or upstream of the facility, an additional 60-minute delay may be experienced while the LNG vessel is berthed or turned. Because of the relatively low volume of recreational boating in the immediate project area, impacts are expected to be minor. Other vessels may be allowed to transit through these security zones with the specific permission of the COTP determined on a case-by-case basis.

Normal transit of the LNG vessels would not affect any parks or state-owned lands listed in table 4.7.3.1-1. Individuals visiting Gleason Point Park, Frost Island, Carlow Island and Moose Island Scenic Area, Quoddy Head State Park and West Quoddy Lighthouse may be able to view the LNG vessels during their transit. Additionally, viewers onshore would be 1 mile or more from the LNG vessels, but in some locations (such as the northwest shore of Campobello Island), the viewing distance could be as little as 0.5 mile. Roosevelt Campobello International Park is located on the southern portion of Campobello Island and would be approximately 1.7 miles from the LNG vessels. See section 4.7.4 for a complete discussion of visual impacts.

The St. Croix Estuary Project commented that the Ganung Nature and Marine Park is located on a 350-acre peninsula within sight of the Downeast terminal. The Quoddy Learning Center is currently being constructed at the Ganung Nature and Marine Park to provide energy and sustainability learning. The Ganung Nature and Marine Park is located approximately 8.5 miles north of the Downeast terminal and would not be affected by the LNG vessel traffic or terminal operation.

The FWS commented that the islands that make up the Maine Coastal Islands National Wildlife Refuge in Washington County, Maine, may be affected by the construction and operations of the project. They are mainly concerned that there would be impacts on birds during nesting season and to other wildlife that use these islands for habitat. The Refuge consists of both mainland properties and a group of islands, among which are five national wildlife refuges—Petit Manan, Cross Island, Franklin Island, Seal Island, and Pond Island. The islands are in the Gulf of Maine south of Grand Manan Island. The islands would not be affected by vessel transit and would not be affected by the project.

The Nature Trust of New Brunswick, Canada, commented that there are Nature Preserves in Head Harbour Passage. They are concerned that LNG vessel traffic through the passage would affect the Nature Preserves' ecological value. The only Nature Preserve that could be potentially affected by LNG vessel traffic is Chocolate Cove Nature Preserve on Deer Island. This preserve would be located about 1.3 nautical miles from the LNG vessels. The Chocolate Cove Nature Preserve is a public park, with cliffs, headlands on either side of Chocolate Cove, two different types of forest, a wetland, a meadow, and a wide range of botanical species, including wild pear bushes. Because of the distance between the LNG vessel route and the preserve, no impacts on the preserve are anticipated.

The U.S. Department of the Interior expressed concern that the Machias Seal Island, which is managed by the Maine Coastal Islands National Wildlife Refuge, may be affected by LNG vessel traffic along the transit route. This island is noted for its significant seabird populations, including the largest tern and alcid breeding colonies in the Gulf of Maine. As indicated above, the islands in the Refuge, including Machias Seal Island would not be affected by the project.

#### 4.7.3.2 LNG Terminal

There are no public lands or other designated federal, state, or local recreation areas located on or within 0.25 mile of the LNG terminal site. The proposed pier would be constructed on submerged lands that are owned by the State of Maine.

Recreational use of the LNG terminal site associated with walking and sightseeing is minimal because it is privately owned and access is limited by steep slopes and rapidly rising tides that inundate the shoreline up to the bluffs on the northern and eastern portions of the terminal site. The shoreland and offshore waters of Mill Cove receive light recreational use for clamming, lobstering, boating, and fishing.

Mill Cove was closed to clamming by the Maine DMR for 30 years due to bacteriological contamination; the Mill Cove shallows was reopened in 2006 and intermittent observations indicate that the northern mud flats are the most visited area of the Cove, with the area in the immediate vicinity of the pier footprint being rarely visited (Moholland 2006). Maine does not have a regulated lobstering season, and fishermen can fish year-round, but they generally only fish when lobsters are catchable (e.g., June/July through November/December, although some lobstermen fish year-round).

Bear Creek Investments announced the development of the Wabanaki Trails and Interpretive Center, to be known as The Trails. The Trails is planned to be located off U.S. Route 1 south of Mill Cove near Pulpit Rock in Robbinston, Maine. The first phase of this project has been designed to include a 6,000-square-foot Interpretive Center, walking trails, and access to the beach. According to Lewis and Malm Architecture (pers. comm., 2008), the designers of the Center, there are no immediate plans to commence construction of the project. We have no additional information since issuance of the draft EIS regarding the status of this project.

Other recreational areas in the vicinity include two Maine DOT scenic turnouts that are located within 0.25 mile of the LNG terminal site along U.S. Route 1. Access to these turnouts would not be affected by construction or operation of the proposed project; however, the tanks and pier would be visible to future visitors of these scenic turnouts.

Construction and operation of the LNG terminal and pier would not significantly affect access to or over state waters and public trust rights (State of Maine submerged lands). Recreational boating, fishing, and shellfishing in the immediate vicinity of the terminal likely would be restricted during construction due to safety concerns. During operation, shoreline fishing and clamming from the immediate vicinity of the LNG terminal site may be prohibited based on the safety and security provisions at the facility that could be established by the Coast Guard. While the exact area of prohibited activities near the project pier has not yet been determined, it would be included by Downeast in its Operations and Emergency Manuals and Facility Security Plan, which are required by federal law and must be submitted to the COTP Sector Northern New England for review and approval at least six months before the terminal is operational. This is reiterated in section 4.6, Risk Mitigation Measures, of the Coast Guard's WSR (Appendix B). The prohibition of shoreline fishing or clamming in the immediate vicinity of the project's pier is not anticipated to be a significant adverse impact.

#### 4.7.3.3 Sendout Pipeline

The sendout pipeline would be within 0.25 mile of the Moosehorn NWR and would cross a network of ATV trails. It also would affect approximately 7.0 acres of state-owned land and cross the land of a proposed racino between MP 11.5 and MP 11.9.

In its initial application to FERC, Downeast proposed crossing approximately 3.5 miles of the Moosehorn NWR in the Baring Division. Recreational opportunities at the Moosehorn NWR include both consumptive (e.g., fishing and hunting) and non-consumptive (e.g., sightseeing) uses. Recreational use is permitted during daylight hours only. Moosehorn NWR has more than 50 miles of dirt roads and trails available for non-motorized activities (e.g., walking, biking, cross-country skiing). Trails include three self-guided interpretive nature trails, and two observation decks offer wildlife watching. In the spring and fall, the public is invited to attend woodcock and waterfowl banding operations. Refuge personnel offer free tours and programs throughout the year, with many events occurring in the summer. Annual events include the Children's Fishing Derby in June and NWR Week in October (FWS 2006).

In a scoping letter to the FERC dated October 18, 2006, the FWS raised several concerns about the sendout pipeline crossing of the Moosehorn NWR. Their concerns included the timing of construction to avoid eagle nesting season; the location of a construction staging area in the Wilderness Area; the disturbance to recreational activities such as hunting, hiking, and snowmobiling during construction; and the potential disturbance to eagle nesting areas in case emergency repair is required during nesting season. Additionally, the FWS was concerned that substantial freezing and thawing during construction could result in considerable damage to refuge roads and habitat.

Downeast submitted a Request for a Special Use Permit for Pipeline Right-of-Way to the Moosehorn NWR on January 25, 2007. Because construction of the sendout pipeline would create short-term impacts on sensitive wetlands, wildlife habitat, and recreational use within the Moosehorn NWR, the FWS denied the Special Use Permit on September 27, 2007.

In January 2008, Downeast submitted an amended application to FERC to revise their proposed sendout pipeline route to avoid the Moosehorn NWR. At its closest point, the proposed sendout pipeline route would be more than 0.25 mile away from the Moosehorn NWR between MP 10.0 and MP 10.5, MP 12.3 and MP 14.3, MP 15.1 and MP 15.2, and between MP 17.3 and MP 17.8, for a total of about 3.1 miles.

Construction is not expected to permanently impact public use of the Moosehorn NWR. It is expected that construction through the area proximate to the Moosehorn NWR would occur in the late summer and is not expected to impact recreational activities any more than other construction activities common in the area (e.g., construction of the Calais International Bridge crossing, flood control dike at the Refuge, improvements to U.S. Route 1). Construction activities are not within or adjacent to those areas within the Moosehorn NWR that the public uses on a regular basis, and thus, construction is not expected to impact recreational users.

Downeast has consistently worked with the Moosehorn NWR to review timing issues and impact mitigation.

In an interagency teleconference call conducted by Downeast on February 15, 2008, the FWS and the COE discussed parcels of land adjacent to the Moosehorn NWR that would be preserved in perpetuity to minimize impacts from future development as mitigation for environmental impacts associated with the Maine DOT's Calais Border Crossing Project. Downeast and Maine DOT representatives met again on May 12, 2008. At that meeting, the Maine DOT confirmed that the land in question, specifically parcel 26-15, which is on the northern border of the Moosehorn NWR between approximately MP 13.0 and MP 13.7, is part of the mitigation plan in the 2006 COE permit for the Calais Border Crossing Project. The Maine DOT indicated that it did not yet have a formal agreement with the FWS for the property transfer. Downeast explained that the amended sendout pipeline route is sited along the eastern boundary of parcel 26-15. During the May 12, 2008 meeting, the Maine DOT indicated that it would be able to provide more detailed mapping of this parcel and feedback on the sendout pipeline route specifically as it relates to Maine DOT properties and activity. Downeast sent pipeline alignment maps to the Maine DOT in July 2008. On December 19, 2011 Downeast filed information with the FERC stating that Downeast has moved forward with securing a property option on private lands outside of the Maine DOT-owned land in question.

A pipeline crossing agreement on lands held by the Washington County Community College (via the Maine Community College System) was reviewed by the System President and the Executive Committee of Trustees. Downeast coordinated the sendout pipeline alignment with the President of Washington County Community College and responded to questions raised by the System Counsel. In June 2008, the System Counsel informed Downeast that the Board of Trustees opposed the pipeline crossing of its property but had indicated that if Downeast were to acquire the right to cross the property (via eminent domain), the System would be willing to review potential pipeline routes in order to ensure minimal disruption to its property.

On January 16, 2006, The Humane Society of the United States Wildlife Land Trust (the Trust) contacted the FWS at the Moosehorn NWR regarding the proposed sendout pipeline. William Kolodnicki, the Moosehorn NWR manager, contacted Downeast on January 17, 2007 to identify the Trust's concerns regarding the sendout pipeline crossing the Gardner Wildlife Sanctuary. Downeast provided a figure of the property depicting the proposed sendout pipeline right-of-way to the Trust and asked that the Trust contact Downeast with additional information. Downeast's January 2008 amendment to its Application rerouting the sendout pipeline to avoid crossing the Moosehorn NWR has effectively resolved the Trust's concern. The modification of the pipeline route would avoid impacts on the Gardner Wildlife Sanctuary.

The sendout pipeline would cross 14,950 feet of ATV trails between MP 0.7 and MP 3.7 in Robbinston and 35,500 feet of ATV trails between MP 21.6 and MP 28.3 in Baileyville. The Robbinston Bushwackers and the St. Croix ATV clubs help manage these trails, and the sendout pipeline right-of-way would cross two segments of these trails.

Pipeline installation would not affect the use of ATV trails during construction, since the network of trails in the area leads to a wide variety of trails adjacent to the right-of-way. No single trail is relied on in the areas mentioned. There will be no limitation on access between points since riders will be able to continue along their path even though pipeline construction is occurring. There would be no net loss of ATV trails upon construction completion. ATV and snowmobile riders could benefit due to the creation of a permanent open corridor, which will be maintained in conjunction with the pipeline operation.

Downeast would avoid construction impacts on snowmobile trails by scheduling construction during months without snow cover. Downeast would continue to work with the State of Maine and with members of the ATV clubs (Howard 2006a; Seavey 2006; Sears 2006) regarding the increased connectivity of their trail systems and temporary loss of access to some areas during construction. In addition to these trails, both clubs use gravel roads, and the sendout pipeline installation would parallel many of these roads and replace the ATV trails, providing new permanently maintained trails.

On lands where ATV use would not be permissible (e.g., private landowners), appropriate signage and/or fencing, public notices, and newspaper notices would be provided to local ATV clubs to restrict these lands from ATV use.

The proposed pipeline from MP 11.5 to MP 11.9 would run along the inside border of a portion of land optioned by the Passamaquoddy Tribe to be developed into a commercial racino. The racino was rejected in a statewide referendum in November 2007. Although the racino project was defeated, the Tribe retained the underlying land purchase option for the property, including the land proposed for the sendout pipeline. The Calais city council also passed a non-binding resolution in March 2011 in support of the racino. Discussions with Tribal representatives regarding an option with Downeast, which would have been secondary to the Tribe's land option, were not conclusive. Preliminary negotiations with the landowner also were not conclusive; however, a follow-up discussion with the landowner resulted in a renewed opportunity to negotiate a primary option on the land. Downeast has indicated that it would continue negotiations with the landowner.

### 4.7.4 Visual Resources

The following section describes the existing environment and the potential visual impact of the proposed Downeast LNG Project and associated facilities in three parts—the waterway for LNG marine traffic, the LNG terminal, and the sendout pipeline. Chapter 315 in 06-096 Code of Maine Rules requires that an applicant for a permit under the NRPA demonstrate that the proposed activity will not unreasonably interfere with existing scenic and aesthetic uses of the scenic resources listed in Section 10 of Chapter 315, e.g., national, state, and local natural resources and lands that are visited by the general public. The following analysis of visual impact considers the existing landscape, the visibility of the proposed potential viewers, and the compatibility of the project with its surroundings. Visibility is assessed in terms of how much would be viewed and at what distance the facilities would be viewed. The viewer analysis considers motorists, tourists, residents, boaters, and hikers.

#### 4.7.4.1 Waterway for LNG Marine Traffic

The waterway for LNG marine traffic is depicted in Appendix F. The waterway for LNG marine traffic follows two different routes from the Bay of Fundy to Quoddy Head. The route chosen by the LNG vessel captain would be determined in consultation with pilots, Transport Canada, and COTP and would depend on visibility, wind, tide cycle, and other such constraints. The eastern route follows an established navigational route (see Appendix F, figure F-1). This route is a known navigation route and should have minimal visual impact. The other route the LNG vessels would use is to the west of Grand Manan (see Appendix F, figure F-1). The western route and transit from Head Harbour Passage to the proposed LNG terminal passes along and between Campobello Island, Indian Island, Deer Island, a number of smaller islands, and the Maine Coast with open water ranging from less than 1.0 mile in width to over 2.0 miles wide. Much of the shoreline is comprised of wooded hillsides and rocky shores. Concentrated development occurs in a few locations such as Eastport, Maine and St. Andrews, New Brunswick. Additional seasonal and year-round residential development is found at scattered locations along the length of the transit route.

LNG vessels servicing the proposed terminal would transport 70,000 to 165,000 $m^3$ of LNG and would average 900 feet in length. Currently, a total of about 135 vessels per year pass through the Head Harbour Passage in the vicinity of Campobello Island. Downeast estimates that an LNG vessel would arrive once every five to seven days in the winter, and once every eight to ten days in the summer along the marine traffic route from Cutler, Maine to the LNG terminal site. The vessel would pass in proximity to Campobello Island and through an area with high quality scenic views of wide ocean expanses, and steep wooded slopes descending to the rocky coastline. Viewers would include motorists on U.S. Route 1 and other roads with views to Passamaquoddy Bay, tourists, boaters, hikers, and residents with sporadic views of the proposed marine traffic route with concentrations of viewers at developed areas like Eastport and St. Andrews. In many locations, viewers would see the entire vessel. Generally, viewers onshore would be a mile or more from the LNG vessels, but in locations such as the northwest shore of Campobello Island, the viewing distance could be less than 0.5 mile. Although the vessels would be large and highly visible, they would be viewed for only short durations in areas already used for shipping by large and small vessels and where people expect to see vessels, and should not result in a significant impact.

#### 4.7.4.2 LNG Terminal

The proposed LNG terminal is located along the coast of Maine in the Town of Robbinston on Passamaquoddy Bay. The location of the LNG terminal and surrounding areas is shown in figure 4.7-1.

Passamaquoddy Bay is the dominant waterbody in the project area, which is predominately in Canadian waters. At the point where the Downeast LNG terminal is proposed, the Bay is approximately 3.0 miles wide. The berthing pier would be about 1.5 to 2.5 miles from the closest points on the Canada shoreline. Along Passamaquoddy Bay, north of the project, there are a number of coves and inlets. Of these, Mill Cove is the widest and deepest cove opening on the Bay, and the others open on the St. Croix River. This region is known for its high tidal amplitude with tidal ranges of up to 27 feet.

In the western portion of the potential viewing area of the LNG terminal, the topography is generally comprised of rolling hills averaging about 200 feet above sea level. Trimble Mountain is the highest point within the viewing area at 533 feet above sea level, and is located approximately 3.1 miles northwest of the proposed LNG terminal. To the north, south and west of the site, most of the land is wooded with open areas along the roads and shorelines. Vegetation is largely spruce-fir forest with some deciduous trees and old field growth. Second growth evergreens on the project site are approximately 50 feet in height.


**Figure 4.7-1**
**Downeast LNG Project**
**Terminal Location Map**

The majority of the area is undeveloped. However, along U.S. Route 1, there are a number of small communities such as North Perry and Robbinston. Outside Robbinston, the development along U.S. Route 1 is characterized by light commercial/retail, rural residential, and tourist-oriented facilities. Across the Bay, about 3.0 miles to the east in New Brunswick, Canada is the community of St. Andrews, which is the largest developed community in the viewing area (see figure 4.7-1). As shown on this figure, the area considered extended out 4.0 miles from the proposed LNG terminal.

The most prominent visual features of the proposed LNG terminal include:

- Marine Terminal – The facilities for LNG vessels docking and unloading, including a 3,862-foot-long pier extending into Passamaquoddy Bay.

- LNG Storage and Regasification Facility – The storage facility located between U.S. Route 1 and Mill Cove includes two LNG storage tanks that are each approximately 259 feet wide and 160 feet above grade. Also included are three vapor fences, a vaporizer building, a compressor building, a main control building, a maintenance warehouse, a water tank, firehouse, security building, and an administration building.

- LNG Vessels – The proposed LNG terminal would be designed to accommodate typical LNG vessels, approximately 900 feet in length. On average, one LNG vessel would be docked at the proposed terminal every five to seven days in the winter and every eight to ten days in the summer.

Due to the forested rolling hills in the area, much of the onshore facility would be screened from areas to the north and south. The outer vapor fence, proposed to be 30 feet high, would be installed along the western site property along U.S. Route 1 and would be a prominent visual feature to vehicles driving along about a one-half mile length of the roadway. Primarily, the Downeast LNG pier would be visible from Mill Cove and portions of Passamaquoddy Bay, the St. Croix River, and St. Andrews. Figure 4.7-1 identifies areas of potential visibility from public viewing points including Passamaquoddy Bay. It also shows the five locations from which photo simulations were developed by Downeast.

Viewers within the area of visibility would include motorists on U.S. Route 1, hikers and tourists on Trimble Mountain and along the coast, commercial and recreational boaters and fishermen on Passamaquoddy Bay and the St. Croix River, residents of and visitors to St. Andrews, New Brunswick, and visitors to the Interpretive Center for the St. Croix Island International Historic Site in Canada. Portions of the storage facilities and terminal would be viewed by four abutting residences, several residences on the north side of Mill Cove, and residences in the vicinity of the intersection of U.S. Route 1 and Ridge Road. Figures 4.7-2 and 4.7-3 provide photo simulations of views from U.S. Route 1. Figure 4.7-4 provides a simulation for views from Trimble Mountain. Also, there are two informal scenic overlooks on the north and south sides of Mill Cove providing views of Mill Cove and Passamaquoddy Bay.

Motorists on U.S. Route 1 traveling south would have a foreground view (0.5 mile or less) of the pier and a portion of the storage tanks and vapor fence above the treeline for about 15 seconds and would have a glimpse from one other area of this highway. Motorists on U.S Route 1 traveling either north or south would have a prominent foreground view of the outer vapor fence while driving along about a one-half-mile length of roadway along the western boundary of the site. From Passamaquoddy Bay, viewing locations would extend from the foreground to the middle-ground (0.5 to 4 miles). All but near views of the tanks and vapor fence (most views) would be backdropped by local topography and vegetation helping to reduce potential visual impact. The pier and LNG vessels would be seen in their entirety across Passamaquoddy Bay and from portions of the St. Croix River. Residents and visitors to St. Andrews, approximately 3.0 miles to the east of the terminal, would view a portion of the tanks and the entire pier and LNG vessels when moored, arriving and departing the proposed port. The view of the proposed terminal from Market Wharf on St. Andrews is discussed further below as Viewpoint 4, and is depicted in figure 4.7-5.

Although there are two National Natural Landmarks, a national and a local preserve, and four properties on or eligible for inclusion in the NRHP, these are outside the viewshed of the proposed LNG terminal and not visible to visitors. There are no state parks within the viewing area for the Downeast LNG terminal. However, a portion of the proposed pier and, about once a week in the winter and twice a week in the summer, an LNG vessel would be viewed from the international center referenced above.

From the St. Croix Island International Historic Site, there should be no adverse visual effect because project views would be limited to potential views of LNG vessels once a week in the winter and twice a week in the summer, at a distance of about 5 miles in a marine environment. As shown in figure 4.7-6, as viewed from the Interpretive Center in Canada, the proposed pier and LNG vessels would be a minor part of the viewed landscape, and the vessels would be compatible with the existing marine use.

As discussed in section 4.7.3, the St. Croix Estuary Project Ganung Nature and Marine Park is approximately 8.5 miles north of the Downeast terminal and should not be affected by the LNG vessel traffic or terminal operation.

Downeast provided five photo simulations to characterize the potential visual impact of the proposed terminal.

**Viewpoint 1 – U.S. Route 1 overlooking Mill Cove (figure 4.7-2):** From this location, the entirety of the pier, the top portion of the storage tanks, and the outer vapor fence (not shown) would be viewed in the foreground (within 0.5 mile) by motorists and tourists. Downeast originally proposed to maintain a 250-foot tree buffer along Passamaquoddy Bay; however, Downeast did not account for the forested areas in its hazard analyses. Therefore, in section 4.12.5, we have recommended that Downeast certify that all trees would be removed from the area between the vapor fences and the shoreline or demonstrate that the spacing of the trees, and any vegetation management plan, would prevent congested areas that could produce offsite overpressures above 1 psi. Given that recommendation, there is a possibility that the forested area visible in this figure would not be present after construction.

**Viewpoint 2 – U.S. Route 1 view toward Liberty Point (figure 4.7-3):** At this location, the pier and a docked LNG vessel, which would be there approximately one or two days a week, would be viewed in the middle-ground (distance of approximately 1.1 miles). The proposed pier has a line similar to background shorelines with a scale that has minimal contrast with and a size that is subordinate to the surrounding landscape.

*Existing view of Mill Cove at low tide from the northern scenic overlook on Route 1 in Robbinston.*

*Photosimulation of proposed Downeast facility from Route 1 at Mill Cove in Robbinston. One storage tank would be visible from this viewpoint at a distance of 2,300'. Light gray is one possible color.*

**Figure 4.7-2**
**Downeast LNG Project**
**Photo Simulation from Mill Cove: Sheet 1 of 3**


*Photosimulation of proposed Downeast LNG facility from Route 1 at Mill Cove in Robbinston. Color of storage tanks will be selected with input from the local community.*


*Photosimulation of proposed Downeast LNG facility from Route 1 at Mill Cove at high tide.*

**Figure 4.7-2**
**Downeast LNG Project**
**Photo Simulation from Mill Cove: Sheet 2 of 3**

*Illustration of potential nighttime conditions, without a LNG carrier docked, from Route 1 at Mill Cove in Robbinston.*

**Figure 4.7-2**
**Downeast LNG Project**
**Photo Simulation from Mill Cove: Sheet 3 of 3**

*Existing view from Route 1 in Robbinston, looking southeast toward Liberty Point.*

*Photosimulation of proposed Downeast LNG pier as seen from Route 1 overlooking Liberty Point. The pier head will be 1.1 miles to the southeast of this viewpoint.*

**Figure 4.7-3**
**Downeast LNG Project**
**Photo Simulation from Liberty Point: Sheet 1 of 3**

*Photosimulation of proposed Downeast LNG pier with docked LNG carrier as seen overlooking Liberty Point. The pier head will be 1.1 miles to the southeast of this viewpoint.*

*Photosimulation of proposed Downeast LNG pier from Route 1 overlooking Liberty Point at high tide. The pierhead will be 1.1 miles to the southeast of this viewpoint.*

**Figure 4.7-3**
**Downeast LNG Project**
**Photo Simulation from Liberty Point: Sheet 2 of 3**

*Illustration of potential nighttime conditions as seen from Route 1 overlooking Liberty Point, without a LNG carrier docked. Lights to the left of pier head in photo from Eastport, approximately 12 miles away.*

**Figure 4.7-3**
**Downeast LNG Project**
**Photo Simulation from Liberty Point: Sheet 3 of 3**

*Existing view from Trimble Mountain looking southeast.*

*Photosimulation of proposed Downeast LNG facility as seen from Trimble Mountain. Storage tanks will be 3.3 miles away.*

**Figure 4.7-4**
**Downeast LNG Project**
**Photo Simulation from Trimble Mountain: Sheet 1 of 1**

*Existing view from Market Wharf in St. Andrews, New Brunswick, Canada, looking west.*

*Photosimulation of proposed Downeast LNG facility as seen from the Market Wharf in St. Andrews, New Brunswick. Storage tanks will be 3.3 miles away.*

**Figure 4.7-5**
**Downeast LNG Project**
**Photo Simulation from St. Andrews: Sheet 1 of 2**

*Photosimulation of proposed Downeast LNG facility with a docked LNG carrier as seen from the Market Wharf in St. Andrews, New Brunswick. Docked LNG carrier will be 2.2 miles away.*

**Figure 4.7-5**
**Downeast LNG Project**
**Photo Simulation from St. Andrews: Sheet 2 of 2**

photograph by Downeast LNG, March 28, 2007

*Existing view looking south from the St.Croix International Historic Site in New Brunswick, Canada.*

**Figure 4.7-6**
**Downeast LNG Project**
**Photo Simulation from Interpretive Center:  Sheet 1 of 3**

Photosimulation of the proposed Downeast LNG facility. The pierhead and approximately 1,500' of the pier will be visible but generally indistinguishable in the background 5.2 miles to the south.

**Figure 4.7-6**
**Downeast LNG Project**
**Photo Simulation from Interpretive Center: Sheet 2 of 3**

Photosimulation of the proposed Downeast LNG facilty with a docked LNG carrier at the pierhead approximately 5 miles to the south. This view approximates the actual view when held 16"+/- from viewer.

**Figure 4.7-6**
**Downeast LNG Project**
**Photo Simulation from Interpretive Center: Sheet 3 of 3**

**Viewpoint 3 – Trimble Mountain Private View Point (figure 4.7-4):** The proposed LNG terminal storage tanks would be viewed at a distance of about 3 miles to the southeast. Due to distance, backdrop and applying appropriate coloration, the tanks would be reasonably compatible with the viewed landscape.

**Viewpoint 4 – Market Wharf in St. Andrews, New Brunswick (figure 4.7-5):** The pier, LNG vessels, and a portion of the storage tanks would be viewed from this location at a distance of approximately 2.4 to 3.2 miles. The storage tanks would be painted a neutral color so as to blend into the vegetated hillside that serves as a backdrop. The hillside behind the tanks would rise above the height of the tanks; therefore, the tanks would blend in with the backdrop. LNG vessels would be present on average of once or twice per week and the arrival, mooring, unloading, and departure sequence is expected to be completed within 24 hours. The pier would be 3,862 feet long, and would be elevated 18.8 feet above the mean high water level. Collectively, these features would have a moderate visual effect from the viewpoint in St. Andrews.

**Viewpoint 5 – Outdoor Exhibit on the Canadian side of the St. Croix River (figure 4.7-6)**: From the St. Croix Island International Historic Site, there should be no adverse visual effect because project views would be limited to potential views of an LNG vessel once or twice a week, at a distance of about 5 miles in a marine environment. As shown in figure 4.7-6, as viewed from the Interpretive Center in Canada, the proposed pier and LNG vessels would be a minor part of the viewed landscape, and the vessels would be compatible with the existing marine use.

To reduce the potential visual impact of the proposed facility, Downeast has proposed the following mitigation techniques:

- Storage Tank Color – The tanks would be painted a neutral color to help reduce the visibility of these large structures and to enhance their ability to blend with the surrounding landscape.
- Passamaquoddy Bay Buffer – Downeast proposes to maintain an undisturbed 250-foot tree buffer along Passamaquoddy Bay. However, Downeast did not account for the forested areas in their hazard analyses. Therefore, in section 4.12.5, we have recommended that Downeast certify that all trees would be removed from the area between the vapor fences and the shoreline or demonstrate that the spacing of the trees, and any vegetation management plan, would prevent congested areas that could produce offsite overpressures above 1 psi. Given that recommendation, there is a possibility that these forested areas would not be present within the terminal area after construction and therefore, there may provide a forested buffer. They also state that side slopes of fill sections would be planted where feasible with low native materials to replicate existing conditions and minimize contrasts in color and texture seen from Passamaquoddy Bay.
- Lighting – We received comments regarding the effects of lighting on nighttime visual aesthetics. To address these concerns Downeast proposes to use equipment specifically designed to reduce off-site light spillage. Where lighting is necessary for security and operations, Downeast proposes to use cut-off fixtures to minimize views of light sources. Cut-off fixtures generally have no direct uplight, reduce glare, and are more efficient by directing all lighting down to the intended area only. Final lighting arrangements would

be considered by the Coast Guard during their review of the Facility Security Plan (FSP). The FSP is required by 33 CFR Part 105 and, as outlined in 33 CFR 105.410(b), must be submitted for review and approval at least 60 days prior to beginning operations.

Downeast did not propose any mitigation to reduce the potential visual impact of the proposed outer vapor fence; therefore, **we recommend that**:

- **<u>Prior to construction of the LNG terminal facilities</u>, Downeast should file with the Secretary for review and written approval by the Director of OEP a mitigation plan to reduce the visual impact of the proposed outer vapor fence.**

The proposed facilities would have a relatively large viewing area comprised of a large portion of the Passamaquoddy Bay and the St. Croix River with views from onshore locations limited by topography and vegetation. The most affected views from onshore (storage tanks and foreground view of outer vapor fence) would occur on U.S. Route 1, from residences along or in proximity to this highway. Due to the proximity, the project facilities would be highly visible to motorists and residents along U.S. Route 1 in the vicinity of the project. From the water the facilities would be highly visible from Mill Cove. Outside of Mill Cove the views grow increasingly distant with less visual impact as one proceeds east across the Bay. In this area, there is a relatively low number of viewers except at St. Andrews, which is located approximately 3 miles to the east.

#### 4.7.4.3 Sendout Pipeline

Potential impacts on visual resources associated with construction and operation of pipeline facilities include alteration of terrain and vegetative patterns. The effects associated with construction through non-forested land would be temporary and minor, as the right-of-way would be restored to pre-existing conditions within a few growing seasons. The effects associated with construction through forested land would be long-term, as a portion of the disturbed forest would be permanently maintained right-of-way, and the remainder left to revegetate and eventually re-establish forest structure. During construction, the cleared and graded right-of-way, as well as the construction equipment operating on the right-of-way, would be visible from surrounding residences and local roads.

The majority of the sendout pipeline would pass through areas of wooded hills crossed by an occasional road with sparse development. For the majority of its length, the proposed sendout pipeline route would parallel existing right-of-way corridors, including the EMEC powerline right-of-way and the M&NE pipeline right-of-way. The heavily wooded area, in conjunction with local topography, would screen most of the right-of-way.

The amended sendout pipeline right-of-way no longer traverses lands of the Moosehorn NWR. No designated visual resource areas are likely to be affected by the sendout pipeline. Due to the few local roads traversing this area and the proximity to areas of low density residential development, the sendout pipeline right-of-way would not be visible to many motorists or local residents. The visual impacts associated with construction would be short-term and minimized by the restoration methods described in section 2.3.1.2. The 10-foot-wide corridor that would be permanently maintained in an herbaceous state would have minimal visual impact.

### 4.7.5 Coastal Zone Management

#### 4.7.5.1 Downeast LNG Project

The Maine CZMA is administered by the Maine Department of Agriculture, Conservation and Forestry, and is a partnership among local, regional, and state agencies. Maine's coastal zone encompasses all political jurisdictions in Maine that have land along the coast or a tidal waterway, such as a river or bay. The zone encompasses Maine's territorial waters, which extend 3.0 miles out to sea (Maine SPO 2008). Maine's coastal zone also extends to the inland boundary of all towns bordering tidal waters and includes all coastal islands. Portions of the Downeast LNG Project would be located within a designated coastal zone management area in Maine. Specifically, the proposed waterway for LNG marine traffic from approximately Friar Roads to Mill Cove (see Appendix F, figure F-33), the LNG terminal, and the proposed sendout pipeline within the towns of Robbinston and Calais from MP 0.0 to MP 15.8 occur within the Maine coastal zone.

The Maine CZMP enforces various state and local environmental laws, regulations, standards, and criteria as the state's coastal policies. The Maine Department of Agriculture coordinates the consistency review as necessary and serves as a single point of contact to receive requests for consistency reviews. Activities and development affecting Maine coastal resources that involve a federal permit or license are evaluated for compliance with the CZMA through a process called "federal consistency review." Table 4.7.5.1-1 provides a list of laws and regulations that comprise the State's enforceable coastal policies, with which a federal action must be consistent. Downeast filed a request for consistency review in December 2006; it was withdrawn by Downeast in November 2007 and Downeast would resubmit the request following issuance of the final EIS. Therefore, **we recommend that**:

- **<u>Prior to construction</u>, Downeast should file with the Secretary documentation of concurrence from the Maine Department of Agriculture that the project is consistent with the Maine CZMP.**

As part of the CZMA, the Maine Mandatory Shoreland Zoning Act requires that municipalities protect shoreland areas by adopting shoreland zoning maps and ordinances that are consistent with guidelines adopted by the Maine BEP. Zoning ordinances define the types of activities that can occur in certain areas. Shoreland areas include those within 250 feet, horizontal distance, of the normal high-water line of any great pond, river or saltwater body; areas within 250 feet, horizontal distance, of the upland edge of a freshwater wetland except in certain situations; and areas within 75 feet, horizontal distance, of the high-water line of a stream. Permits are required from each municipal planning board if land uses and/or structures could impact areas protected by the Mandatory Shoreland Zoning Act. The project would be located in two civil divisions of Maine's coastal zone; the LNG terminal would be located in Robbinston and the sendout pipeline would be located in both Robbinston and Calais. The waterway for LNG marine traffic, although partially located within Maine's coastal zone, is not subject to the Mandatory Shoreland Zoning Act.

TABLE 4.7.5.1-1

**Maine Coastal Laws and Regulations**

| Regulations | Applicable Subsection |
|---|---|
| Natural Resources Protection Act (38 MRSA §§480-A to 480-S; 480-U to 480-Z) | Wetlands Protection rules (Maine DEP rules chapter 310) |
| | Coastal Sand Dune rules (Maine DEP rules chapter 355) |
| | Permit by Rule standards (Maine DEP rules chapter 305) |
| | Significant Habitat rules (Maine DIFW rules chapter 10) |
| | Scenic Impact rules (Maine DEP rules chapter 315) |
| Mandatory Shoreland Zoning Law (38 MRSA §§435 to 449) | Guidelines for Municipal Shoreland Zoning Ordinances (Maine DEP rules chapter 1000) |
| Site Location of Development Law (38 MRSA §§481 to 485-A; 486-A; 487-A to 490; 490-A to 490-Z) | Definitions of terms used in the site location of development law and regulations (Maine DEP rules chapter 371) |
| | Policies and procedures (Maine DEP rules chapter 372) |
| | Financial capacity standard (Maine DEP rules chapter 373) |
| | Rules regarding the traffic standard |
| | No adverse environmental impact standard (Maine DEP rules chapter 375) |
| | Soil types standard (Maine DEP rules chapter 376) |
| | Review of roads (Maine DEP rules chapter 377) |
| | Variance criteria; performance standards (storage of petroleum products) (Maine DEP rules chapter 378) |
| | Planning permit (Maine DEP rules chapter 380) |
| | Stormwater Management rules (Maine DEP rules chapter 500) |
| | Direct Watersheds of Lakes Most at Risk from Development (Maine DEP rules chapter 502) |
| MDOT Traffic Movement Permit (23 MRSA §704-A) | |
| Erosion Control and Sedimentation Law (38 MRSA §420-C) | |
| Subdivision Law (30-A MRSA §4401 to 4407) | |
| Maine Rivers Act (12 MRSA §§403 and 407) | |
| Maine Waterway Development and Conservation Act (38 MRSA §§630 to 636; 640) | |
| Coastal Management Policies Act (38 MRSA §1801) | |
| Protection and Improvement of Air Law (38 MRSA §§349; 581 to 610-A) | |
| Protection and Improvement of Waters Act (38 MRSA §§347; 361 to 367; 371-A to 372; 410-N; 411 to 424; 451 to 455; 464 to 470) | |
| Nutrient Management Act (7 MRSA Part 10) | |
| Land Use Regulation Law (12 MRSA §§681 to 689) | |
| LURC Rules and Regulations, Chapter 10- Land Use Districts and Standards | List of Coastal Islands in the Jurisdiction of the Maine Land Use Regulation Commission |
| | LURC Rules and Regulations, ch. 10 – Land Use Districts and Standards |

| TABLE 4.7.5.1-1<br><br>**Maine Coastal Laws and Regulations** | |
|---|---|
| **Regulations** | **Applicable Subsection** |
| Maine Hazardous Waste, Septage and Solid Waste and Management Act (38 MRSA §§1273; 1281; 1301 to 1310-BB; 1316 to 1316-L; 1317 to 1319-W; 1362; 1609-10; 1661-1661-C; 1851-2;2133, sub §2(A); PL 1999 c.348; 2157; 2302 to 2313) | |
| Nuclear Facility Decommissioning Laws (PL 1999 c. 741) | |
| Oil Discharge Prevention & Pollution Control Law (38 MRSA §§344 to 349; 541 to 560; 563 sub-§1(A) and 2;<br>563-A-C; 564; 566-A; 568-A; 569-A to 569-B; 570-A to 570-L; 585-D; 585-H | |
| Marine Resources Law (12 MRSA §§6171 to 6192; 6432-A) | |
| Coastal Barrier Resources System Act (38 MRSA §§1901 to 1905) | |
| Maine Endangered Species Act<br>(12 MRSA §§12801-12809; 12 MRSA §6971-6977; 12 MRSA §10001, sub-§§19 and 62) | Endangered Species Rules (Maine DIFW Chapter. 8) |

Robbinston has adopted a Land Use and Development Code for regulating the uses of land within the town boundaries. The Land Use and Development Code requires that all new developments obtain a land use permit from the Robbinston Planning Board (Robbinston Comprehensive Plan 1996), which was granted for the LNG terminal on February 16, 2006 under its Shoreland Zoning Ordinance, and a Conditional Land Use Permit. The Downeast LNG Project is in conformance with this aspect of the Maine CZMP. Downeast consulted with town officials in Robbinston concerning its requirements for the construction of the sendout pipeline within specially designated lands.

The City of Calais has also adopted a Shoreland Zoning Ordinance, where essential services such as public utilities (e.g., natural gas transmission lines, electric transmission lines, sewage collection, and treatment facilities) may be permitted in the Shoreland Districts upon application to the City of Calais Planning Board. Downeast consulted with city staff concerning its requirements for the construction of the sendout pipeline within specially designated lands. The City Manager and Code Enforcement Officer for Calais, James Porter, reported to Downeast that the sendout pipeline, as a regulated utility facility, would fall under zoning exemptions (Porter 2006).

There are a number of state permit requirements that comprise the Maine CZMP, but the two more significant programs are the NRPA and the Site Location of Development Law, which are briefly discussed below.

Under the NRPA, portions of the LNG terminal and sendout pipeline would be installed under a Permit by Rule allowing for the installation, maintenance, and replacement of a submerged utility line across a coastal wetland, freshwater wetland, great pond, river, stream, or brook excluding outstanding river segments identified in 38 Maine Revised Statute Annotated (MRSA) Section 480-P. Downeast filed an application with the Maine DEP on December 19, 2006, withdrew this application on November 11, 2007, and plans to re-submit the application following issuance of the final EIS. Downeast would obtain a permit prior to construction.

Under the Site Location of Development Law, projects occupying more than 20 acres must be reviewed. The LNG terminal and applicable portions of the sendout pipeline would obtain this approval prior to construction. Downeast filed an application on December 19, 2006, withdrew this application on November 11, 2007, and plans to re-submit the application following issuance of the final EIS. A determination that the project is consistent with the Maine CZMP must be received prior to construction of the LNG terminal and pipeline.

### 4.7.6 Hazardous Waste Sites

#### 4.7.6.1 Waterway for LNG Marine Traffic

There are six onshore hazardous waste sites located along the waterway that would be used by LNG vessels. All six sites are mapped within the Town of Eastport. These sites would not be affected by LNG vessel transit during normal operation.

#### 4.7.6.2 LNG Terminal

Downeast conducted a search of available environmental database records and no sites associated with the storage, release, or disposal of petroleum products or hazardous materials or groundwater contamination were identified within 0.25 mile of the LNG terminal site (EDR 2006; EGAD 2006). For more detailed discussion see section 4.2.7.1.

#### 4.7.6.3 Sendout Pipeline

Downeast conducted a search of available environmental database records within 0.25 mile of the sendout pipeline route. Based on the results of the search, 15 sites associated with the storage, release, or disposal of petroleum products or hazardous materials or contaminated groundwater were identified within 0.25 mile of the sendout pipeline centerline. A list of the identified sites, locations, and approximate milepost along the sendout pipeline route are shown in tables 4.2.7.2-1 and 4.2.7.2-2.

## 4.8 SOCIOECONOMICS

Several potential socioeconomic effects may result from construction and operation of the proposed LNG project. Many of these potential effects are related to construction and include the number of local and non-local construction workers who would work on the project; their income and local expenditures; and their impact on population, public services, and temporary housing during construction. Other potential effects related to construction include local construction expenditures by Downeast. Potential economic benefits associated with operation of the project include increased property tax revenue, increased job opportunities and income, and ongoing local expenditures by the company.

The proposed project consists of two components, the LNG terminal and the sendout pipeline. A discussion of the effects of the proposed project to local population, the economy, housing, tax revenues, public services, and environmental justice is provided below.

The Save Passamaquoddy Bay group commissioned a study of the potential impacts from an LNG terminal development that would be located on Passamaquoddy Bay. This report is referred to as the "Whole Bay Study" and was filed with the Commission on October 2, 2006. The Study primarily focuses on the socioeconomic and fiscal impacts of constructing and operating LNG facilities in the Passamaquoddy Bay area. Some concerns expressed in the Study have also been raised by other members of the public in their scoping comments. The issues raised by the Study have been fully evaluated within this section of the EIS.

### 4.8.1 Population

The proposed project would be located in Washington County, Maine. Washington County is the easternmost county in the United States with a land area of 2,568 square miles and a low population density. The county seat is Machias, approximately 45 miles west of the Downeast LNG Project area. Washington County's 2010 population was 32,856. The county ranked 14th in population among Maine's 16 counties, but 5th in land area.

Based on U.S. Census Bureau (USCB) population estimates for 2010, the county's population declined by 3.2 percent between 2000 and 2010. By comparison, Maine's population grew by 4.1 percent and the U.S. population grew by 8.0 percent between 2000 and 2010. The county's average population density in 2010 was 12.8 persons per square mile, and the median age was 46.1 (USCB 2000, 2010). Table 4.8.1-1 presents population trends for the project area communities and comparison areas. As the table shows, many of the communities that would be affected by the project have experienced the overall trend of declining populations that has typified Washington County (and most rural areas of the United States). Communities within the project area declined by 5 percent between 2000 and 2010.

TABLE 4.8.1-1

**Population Trends, Downeast LNG Project Area and Comparison Regions**

| Area | 2000 | 2010 | % Change, 2000-2010 |
|---|---|---|---|
| United States | 281,421,906 | 303,965,272 | 8.0% |
| Maine | 1,274,923 | 1,327,665 | 4.1% |
| Washington County | 33,941 | 32,856 | -3.2% |
| Project Area | | | |
| Robbinston | 525 | 592 | 12.8% |
| Alexander | 514 | 350 | -31.9% |
| Baileyville | 1,686 | 1,544 | -8.4% |
| Baring Plantation | 273 | 316 | 15.8% |
| Calais | 3,447 | 3,192 | -7.4% |
| Charlotte | 324 | 311 | -4.0% |
| Cooper | 145 | 202 | 39.3% |
| Eastport | 1,640 | 1,425 | -13.1% |
| Meddybemps | 150 | 136 | -9.3% |
| Pembroke | 879 | 980 | 11.5% |
| Perry | 847 | 943 | 11.33% |
| Princeton | 892 | 898 | 0.7% |
| Pleasant Point Reservation | 640 | 475 | -25.8% |
| Total Project Area | 11,962 | 11,364 | -5% |

Source: USCB 2000, 2010

### 4.8.1.1 LNG Terminal

Short-term demographic impacts would result from an influx of construction workers during the construction phase of the LNG project, anticipated to last approximately three years. The construction workforce is estimated to average 332 workers, with peaks of about 650 workers at various points in the project. Downeast has assumed that 20 percent of the workforce would be specialized workers from outside the project area, and that approximately 50 percent of the remaining general workers would also be from outside the project area, for an average total of about 200 workers potentially relocating. If it were conservatively assumed that all the non-local workers would move into the area with their families, the county's population could increase by 1.7 percent and the project area's population by 4.9 percent.[17] With the existing trend of declining area populations, this would be a beneficial impact.

Long-term impacts on local population would result from the addition of 78 permanent staff, consisting of 4 tugboat crews and 62 terminal staff, and their families. Given the extent of marine activities in the project area, it is highly likely that most if not all of the tugboat operators, and many of the terminal staff, would be hired locally. Even if all 78 workers were to relocate into the project area with their families (for a total of approximately 222 persons), Washington

[17] This estimate is based on an average family size of 2.76 in Washington County (USCB 2010).

County population would increase by only 0.7 percent, while population in the project area would rise by 2 percent. Again, this would be a beneficial impact on local population.

#### 4.8.1.2 Sendout Pipeline

The pipeline construction labor force is estimated at 320 workers. Many workers would likely be hired from among the local employment force. Since the construction period is expected to be no more than about nine months, it is unlikely that non-local workers would permanently relocate to the project area, or would bring their families during the construction period. Population impacts from construction of the sendout pipeline are expected to be minimal.

### 4.8.2 Economy

This section contains a discussion of the local and regional economy, including employment and personal income, property values, tourism, the fishing industry, and agricultural industries. Section 1.1, Purpose and Need, includes a discussion of United States and New England natural gas trends, supply and demand issues, and the role of LNG.

#### 4.8.2.1 Employment and Personal Income

Washington County's 2011 civilian labor force averaged 14,278, according to the Maine Department of Labor. The 2010 civilian labor force of 15,603 in Washington County represented an increase of 1.6 percent over the 2000 civilian labor force of 15,354. In contrast, between 2000 and 2010, the civilian labor force in Maine increased by 7.4 percent and in the United States, by 11.9 percent (USCB 2000, 2010; Maine Department of Labor 2013).

As of 2011, the government and government enterprises sector provided the greatest amount of employment (25.2 percent of the civilian labor force) in Washington County. The retail sector provided 16.5 percent of the county's jobs, manufacturing provided 11.1 percent, and construction jobs accounted for 2.5 percent (BEA 2006). The average 2011 unemployment rate for the State of Maine was 7.7 percent, while the unemployment rate for Washington County was 7.6 percent, the highest unemployment rate in the state (Maine Department of Labor 2013).

#### 4.8.2.2 Commercial Shipping

The Port of Eastport has experienced varying commercial shipping activity over the past decade. Data from the DOT showed a total of 66 vessel calls in 2004, a 65 percent increase over 2002. However, since 2004, vessel traffic has declined sharply, with only seven calls recorded in 2007 (the latest year available). During 2002 to 2004, the vast majority of traffic was general cargo, and in 2007 all shipping was general cargo (MARAD 2009). Much of Eastport's shipping decline resulted from the closing or downsizing of paper mills in the area. Table 4.8.2.2-1 shows commercial vessel traffic by type for the Port of Eastport. During 2002-2004, the vast majority of traffic was general cargo.

Vessels bound for the Downeast LNG terminal can take one of two routes; the western route, which transits Grand Manan Channel to the west of Grand Manan Island; or the eastern route that follows the traffic lanes in the Grand Manan basin on the easterly side of Grand Manan Island towards the port of St. John, New Brunswick, turning west at the designated Eastport turn-out lane. Both routes converge offshore in the general vicinity of the entrance to Head Harbour Passage, north-northeast of Campobello Island. Commercial marine traffic and other economic activity along the waterway route that would be used by the LNG vessels could be affected by the passage of the LNG vessels. The Coast Guard's WSR recommends the development of safety and security zone parameters that would be developed with the COTP in coordination with the government of Canada (see section 4.12 for more detail on marine traffic safety). The Coast Guard has indicated in the WSR that the combined moving safety/security zone for an LNG vessel in Passamaquoddy Bay would be 2 nautical miles (4,000 yards) ahead of the vessel, 1 nautical mile (2,000 yards) astern of the vessel, and 0.25 mile (500 yards) abeam each side of the vessel. The speed of the LNG vessel would vary between about 5 and 10 knots[18] through the transit route in accordance with waterway conditions, and decrease to 2 knots as the vessel approaches the terminal. At 10 knots, a vessel would take approximately 18 minutes to pass any given point.

TABLE 4.8.2.2-1

**Commercial Vessel Traffic, Port of Eastport, Maine, 2006-2010**

| | | 2006 | 2007 | 2008 | 2009 | 2010 | % Change 2006-2008 | % Change 2006-2010 |
|---|---|---|---|---|---|---|---|---|
| **All Types a/** | **Calls** | **12** | **7** | **15** | **3** | **7** | **25%** | **-42%** |
| | **Capacity** | **467,986** | **97,202** | **486,980** | **55,306** | **135,217** | **4%** | **-71%** |
| Tanker (Product) b/ | Calls | 1 | 0 | 0 | 0 | 0 | 0.0% | 0.0% |
| | Capacity | 16922 | 0 | 0 | 0 | 0 | 0.0% | 0.0% |
| Dry Bulk c/ | Calls | 6 | 0 | 0 | 0 | 0 | 0.0% | 0.0% |
| | Capacity | 253,066 | 0 | 0 | 0 | 0 | 0.0% | 0.0% |
| General Cargo d/ | Calls | 5 | 7 | 15 | 3 | 7 | 200% | 4% |
| | Capacity | 197,998 | 97,202 | 486,980 | 55,306 | 135,217 | 146% | -31.7% |
| **Capacity as % of Total** | | | | | | | | |
| Tanker (Product) | | 3.6% | 0.0% | 0.0% | 0.0% | 0.0% | | |
| Dry Bulk | | 54.1% | 0.0% | 0.0% | 0.0% | 0.0% | | |
| General Cargo | | 42.3% | 100.0% | 100.0% | 100.0% | 100.0% | | |

a/ Only vessel types that called on Eastport are included. The following types were excluded: Crude Tanker, Container: "Ro-Ro"[roll-on, roll-off cargo loading vessels]: Vehicle; Gas Carrier; Combination.
b/ All tanker traffic belonged to the Product Tanker subcategory of Tanker. Product tanker = 10,000 - 69,999 (deadweight DWT).
c/ Dry Bulk :Bulk Vessels, Bulk Containerships, Cement Carriers, Ore Carriers, Wood-chip Carrier.
d/ General Cargo: General Cargo Carriers, Partial Containerships, Refrigerated Ships, Barge Carriers, Livestock Carriers.
Source: DOT Maritime Administration (MARAD) 2010.

Downeast estimates that there would be one vessel every five to seven days in the winter (slightly more often than once per week), and one vessel every eight to ten days in the summer (or about once every week and a half), approximately 60 vessels per year. In locations where the waterway is narrow, some mariners attempting to travel in the opposite direction of an LNG vessel traveling at 10 knots may need to wait up to 18 minutes for the LNG vessel to pass before proceeding on its way. The delay would increase up to 36 minutes when the LNG vessel is traveling at 5 knots and up to 60 minutes when the LNG vessel is traveling at 3 knots. For mariners near or upstream of the facility, an additional 60-minute delay may be experienced while the LNG vessel is berthed or turned. Other vessels may be allowed to transit through the LNG vessel security zones with the specific permission of the COTP determined on a case-by-case basis. Mariners and other users of the waterway would receive advance warning of an LNG vessel transit and associated waterway restrictions through various established communication methods and public service announcements. Given the limited amount of LNG vessel traffic, the

[18] A knot equals 1.0 nautical mile (6,016 feet) per hour, and is equivalent to 1.15 statute (land) mph.

implementation of vessel traffic management practices, as recommended by the Coast Guard's WSR, the advance notice to United States and Canadian authorities from the LNG vessels transiting the area, and the limited time that nearby marine traffic could be interrupted, impacts on commercial marine activity would be insignificant.

One expected beneficial impact is the increase in the demand for pilots to guide the LNG vessels safely through the Western Passage to the LNG facilities, and tugboats and associated crews to assist the vessels. According to the Coast Guard, as per the current, informal practice, the LNG vessels would pick up pilots at the East Quoddy Head Pilot Station. Downeast expects that each vessel would ultimately need three to four tractor tugs (depending on carrier size) during transit of the waterway to the LNG facility. The proposed project would increase employment opportunities for pilots, tug captains, and tug crews, and would increase the need for tugboats and tug maintenance services.

#### 4.8.2.2.1 LNG Terminal

Downeast has stated that it intends to hire locally to the extent possible, and it is assumed that within the constraint of union labor rules, some workers would have opportunities for additional job training. Therefore, the proposed LNG project would create short-term beneficial impacts on both local and regional employment during the construction phase, with additional long-term benefits to the local workforce if workers were able to improve their skills.

Downeast forecasts that construction of the proposed LNG project would create an estimated total average of 569 jobs, with a peak of about 650 jobs. Work at the LNG terminal site would require an average annual employment base of 332 workers. Based on the anticipated schedule, 75 percent of these workers would be on-site during peak construction activities (approximate average of 249 workers on-site at any one moment in time). Downeast also estimated that approximately 320 pipeline workers would be required during a nine-month pipeline construction period.

Downeast commissioned the University of Maine to conduct a study of the economic impacts of the proposed Downeast LNG Project.[19] The findings of this study indicate that construction activities would support an estimated 1,053 jobs throughout the state in each of the three years. Such an increase in employment would be equivalent to 0.16 percent of total state employment as of 2011. Maine workers associated with Downeast's pre-operations activities would receive an estimated $42.9 million in income per year. Furthermore, the study found that terminal construction would support an estimated 375 jobs in Washington County (counted in the statewide impact of 1,053 jobs noted above) in each year of the construction project. These workers would receive an estimated $15.3 million in income per year. An impact of 375 new jobs would be equivalent to 2.9 percent of total employment in Washington County as of 2011 (Maine Department of Labor 2013). The study used an employment multiplier of 2.04, meaning that each Washington County worker employed on the construction project would support an additional 1.04 workers within the county. However, it should be noted that the U.S. Bureau of

[19] Todd Gabe Jonathan Rubin, *et al.* 2005. *Economic and Fiscal Impacts of a Proposed LNG Facility in Robbinston, Maine*. University of Maine REP Staff Paper #556. November. The research was supported by a grant from Downeast LNG. The study assessed other LNG projects and studies, and used the IMPLAN model to forecast employment requirements and associated impacts (indirect employment, income and tax generation).

Economic Analysis[20] calculated an employment multiplier of 1.44 for Washington County, which would result in a smaller number of indirect jobs and lesser amounts of secondary income than predicted by the University of Maine study. By either calculation, the creation of secondary jobs and income would be a beneficial impact for the project area.

Of the $400 million expenditure to construct the Downeast LNG Project, the University of Maine study estimated that $222.5 million would be spent within the state over three years, resulting in beneficial impacts within the project area, the county, and the state.

Prior to beginning operations, Downeast plans to purchase tugboats that would be built by a Maine company located outside of Washington County. This spending represents another short-term impact that would occur during the construction phase. The University of Maine study assumed that the boats would be built over a three-year period and that $8 million of spending would occur in each year, directly supporting 52 jobs per year and providing $2.1 million in annual labor income. Along with these direct impacts, the multiplier effects associated with spending by the boat builder and its workers would amount to an estimated annual 35 jobs and $1.1 million in labor income, for a total of 87 temporary jobs and $3.2 million in labor income per year. This would be a beneficial impact on the region.

When the proposed project begins operation, it would affect the economy through the creation of direct employment opportunities and the purchases of goods and services from other businesses located within Washington County and the rest of Maine, providing beneficial long-term impacts on the area.

Operation of the proposed LNG facilities would employ 78 workers, including 16 tugboat operators and 62 positions within the terminal. Tugboat operators' and facility workers' annual salaries, including benefits, are expected to average $51,750 and $69,000, respectively. In addition, Downeast expects to purchase $4.0 million worth of goods and services from other Maine businesses on an annual basis. The employment multiplier suggests that operation of the project would support a total of 253 jobs across Maine over the lifecycle of the LNG terminal, which is expected to be 30 years or longer. These workers would receive an estimated $10.7 million in income per year. A statewide impact of 253 jobs would be equivalent to 0.036 percent of total state employment as of 2004.

Focusing on local effects, the University of Maine study found that the LNG terminal operations would support a total of 187 jobs in Washington County over the terminal's lifecycle. These workers would receive an estimated $8.1 million in income per year. A county-level impact of 187 jobs would be equivalent to 1.33 percent of Washington County's total employment in 2000.

The local availability of goods and services needed by the LNG facilities would determine the proportion of the $4.0 million in anticipated annual spending (during the 30-year or longer lifecycle of the import terminal) that would take place in Washington County. Based on information from an economic model for the State of Maine, the University of Maine study assumed that the LNG facility would purchase $2.35 million of goods and services in Washington County on an annual basis.

[20] The U.S. Bureau of Economic Analysis (BEA), Regional Economic Analysis Division, uses an updated version of the Regional Industrial Multiplier input-output model (RIMS II) to estimate secondary impacts that are specific both to certain types of industries and to certain regions. The RIMS II Multipliers presented here are based on BEA's 2003 national annual input-output (I-O) accounts and BEA's 2003 regional economic accounts (BEA 2006).

The Town of Robbinston and Downeast have finalized a "Host Community Benefits Agreement" that outlines a number of commitments being sponsored by Downeast in the event the project is developed. Downeast stated that these commitments would serve to ensure that project benefits are shared with the people of Robbinston and that certain obligations and services are documented in a legally binding document.

Under the Host Community Benefits Agreement, Downeast has agreed, subject to the availability of sufficient qualified local firms and personnel, to set aside 5.0 percent of the construction contracting value for the LNG project that is to be performed within the State of Maine for contractors that are based in Washington County. In addition, Downeast has agreed to provide incentives to its construction contractors to employ Washington County local workers and to make available to qualified hires, as needed, up to five months of basic construction job training through a qualified training institution or entity. For operations, Downeast has also agreed (subject to the availability of a sufficient pool of qualified local workers) to maximize the levels of employment of local workers and to pay the costs of any training required for local workers hired to work.

#### 4.8.2.2.2 Sendout Pipeline

In contrast to the estimated 320 pipeline construction workers, only 4 permanent staff would be required for operation and maintenance of the sendout pipeline. Therefore, there would be small beneficial impacts resulting from any local purchase of goods and services, and expenditures by inspection and maintenance personnel.

### 4.8.2.3 Property Values

Many local residents expressed concerns during the scoping process about the proposed project's impact on property values, insurance rates, and any visual impacts that could affect local tourism. Comments were also expressed regarding property devaluation caused by the construction and operation of the sendout pipeline.

The transit route is currently being used by large vessels enroute to other United States and Canadian facilities. The addition of one LNG vessel in passage along the waterway every 8 to 10 days would be very unlikely to adversely affect the value of properties along the shoreline. Many residents along waterways enjoy observing ships and other marine traffic and consider it an "amenity" of shoreside living.

#### 4.8.2.3.1 LNG Terminal

Appraisal methods used to value land are based on objective characteristics of the property and any improvements. The impact an LNG facility may have on the value of a tract of land depends on many factors, including size, the values of adjacent properties, presence of other industrial facilities, the current value of the land, and the current land use. Regional studies have been conducted to evaluate the potential effects of LNG terminals and other types of energy facilities on local property values. A 1995 study surveyed several land assessors from the Commonwealth of Massachusetts (Real Estate Counseling Group of Connecticut 1995). A 1993 study examined the effects of 262 facilities on standardized 1,000-square-mile areas across the United States, 11 of which were LNG facilities (Clark and Nieves 1993). These studies concluded that the presence of an LNG facility did not have a significant positive or negative impact on either wages or property values. Based on information from these studies, it is unlikely that the construction and operation of the LNG terminal would have significant adverse impacts on property values in the surrounding area.

Homeowner insurance rates are generally set on a countywide basis, with individual rate adjustments made to reflect the age and value of the property and the claims record of the owner. Insurance rates are not based on the surrounding landscape or structures at the local level. It is not anticipated that the presence of the proposed LNG facilities would adversely affect the insurance rates of nearby residences.

A land parcel's property taxes are generally based on the actual use of the land. Construction of the LNG facilities would not likely change the general use of the land for surrounding properties. If a landowner feels that the presence of the LNG facilities reduces the value of his or her land, resulting in an overpayment of property taxes, he or she may appeal the assessment and subsequent property taxation to the local property taxation agency.

Under the Host Community Benefits Agreement, Downeast has agreed to compensate owners of any affected business in the town that was in operation as of July 11, 2005, and that is determined by an independent arbitrator to have been adversely impacted solely by the construction and operation of the project. Downeast has also agreed to compensate residential property owners whose property abuts the project boundary, is located immediately across U.S. Route 1 from the terminal site, or is on the north shoreline of Mill Cove and faces the shoreline portion of the terminal site. Property owners would receive a one-time impact fee of $25,000 or would be compensated for the reduced market value of properties that were sold.

#### 4.8.2.3.2 Sendout Pipeline

Comments were received during the scoping process regarding property devaluation caused by the construction and operation of the sendout pipeline. Appraisal methods used to value land are based on objective characteristics of the property and any improvements. The impact a pipeline may have on the value of a tract of land depends on many factors, including the size of the tract, the values of adjacent properties, the presence of other utilities, the current value of the land, and the current land use. Subjective valuation is generally not considered in appraisals. This is not to say that the pipeline would not affect resale values. A potential purchaser of property may make a decision to purchase based on his or her planned use, such as agricultural, future subdivision, or second home on the property in question. If the presence of a pipeline renders the planned use infeasible, it is possible that a potential purchaser would decide not to purchase the property. However, each potential purchaser has different criteria and differing capabilities to purchase land.

The effect of an easement on property values would be negotiated between Downeast and affected landowners during the easement acquisition process, which is designed to provide fair compensation to the landowner for the right to use the property for pipeline construction and operation. To the extent eminent domain might be required to acquire a section of the right-of-way, established legal methods of valuation would be used to compensate owners for any lost value.

Property taxes on a parcel of land are generally based on its actual use. Construction of the pipeline would not change the general use of the surface property, but it would preclude the construction of aboveground structures (and other activities involving excavation) along the permanent right-of-way. The pipeline right-of-way must also be kept clear of timber. If a landowner feels that the presence of a pipeline easement reduces the value of his or her land, resulting in an overpayment of property taxes, he or she could appeal the issue of the assessment and subsequent property taxation to the local property taxation agency.

#### 4.8.2.4 Tourism

According to the Maine Department of Economic and Community Development (Maine DECD) (2006), the travel and tourism industry continues to be a significant and growing contributor to Maine's economy. The entire state is visited by tourists, including the Downeast LNG Project area and surrounding environs. Attractions in the state include natural resource areas, recreation and hunting/fishing, water-related activities, casinos and cruises, and others. In particular, Saint Andrews, Campobello and Eastport are using local initiatives and investments to actively expand local cruise ship tourism. These ports-of-call attracted 11 ships during 2012 that resulted in estimated local expenditures of at least $100 per passenger and total local expenditures of close to $1 million (McIntyre 2013). From 2009 to 2013, the Town of Saint Andrews invested $900,000 in the Town Market Wharf to support large cruise ships and smaller ships (Choptiany 2013) and investors have committed as much as $5 million at Welshpool in Campobello for wharf improvements. In addition, the island of Grad Manan has been working with Saint Andrews and Eastport to attract small expedition ships to the area (McIntyre 2013).

The Maine Department of Tourism reports that net direct tourism expenditures amounted to $4.9 billion in 2011, which was made up by $1.2 billion of expenditures in lodging, $569 million in transportation, $1.3 billion in food, $1.5 billion in retail goods, and $351 million in recreation. Net spending by overnight leisure travelers (41.3 percent) was greater in every category as compared to net spending by day leisure travelers (58.7 percent) (Maine Department of Tourism 2012). According to the Maine Department of Tourism, 653 people were employed in leisure and hospitality in Washington County in 2011 and made a total of $8.2 million in wages (Maine Department of Labor 2013). State tax rates are 5 percent for sales and 7 percent for lodging and food; there is no local community option to tax. However, tourism studies (Longwoods International 2004) have found that while 39 percent of first-time visitors listed Downeast/Acadia as their main destination, only 18 percent of repeat visitors listed Downeast/Acadia as their main destination. In the project area, Eastport was the choice of only 6.0 percent of first-time visitors and 3.0 percent of repeat visitors, while Calais was selected by 7.0 percent of both first-time and repeat visitors.

As another tourism measure, taxable retail sales data for 2012 from the Maine Office of Policy and Management (2013) show that Washington County, had $2.2 million in restaurant and $734,600 in lodging sales, accounting for 16.7 percent of total retail sales (Maine Office of Policy and Management 2013).

LNG vessels bound for the Downeast LNG terminal can take one of two routes; the western route, which transits Grand Manan Channel to the west of Grand Manan Island; or the eastern route that follows the traffic lanes in the Grand Manan basin on the easterly side of Grand Manan Island towards the port of St. John, New Brunswick, turning west at the designated Eastport turn-out lane. Both routes converge offshore in the general vicinity of the entrance to Head Harbour Passage, north-northeast of Campobello Island. Along the transit route, recreational activities are not expected to be significantly affected. From 2010 to 2013, the tour boat industry has generated revenues of $54,000 as a result of passenger capacity, $18,000 for berthing fees for the town of St. Andrews, and $5.4 million in ticket sales at the wharf for the tour boat operators. The tour boat industry also contributes high seasonal employment (Boucher 2013). Whale watching vessels generally dock in St. Andrews, Canada, and access whale watching areas via Letite Passage, rather than along the proposed transit route for LNG vessels. Other whale watching vessel transits are not expected to be significantly affected by LNG shipping. However, disruptions to local whale habitat from large vessels may require the whale watching vessels to travel to farther areas, adding expenses for the tour boat operators in fuel costs and loss of time (Boucher 2013). LNG vessels would transit the Western Passage less than once a week (every eight to ten days) during the major whale watching season, from mid-June to September (Bay of Fundy.com 2009). As discussed in section 4.7.3, recreational boating traffic is extremely light with only a handful of vessels operating on any given day. Several local festivals or events occur along the shoreline of the LNG vessel transit route, including the Eastport Fourth of July Celebration, with large U.S. Navy vessels present, and the Salmon Festival. These events reportedly provide a major portion of the summer revenue stream for local businesses. However, these events would not likely be adversely affected by the Downeast operations, since LNG vessel scheduling can usually be pre-established to avoid interference with special waterway event days. In any event, the 15 to 30 minute transit of a Downeast LNG vessel past Eastport approximately two times (once inbound and once outbound) every eight to ten days in the summer should not have a material impact on Eastport summer business activities or visitors. Eastport residents, tourist-type businesses, and the Port of Eastport should not incur a significant adverse impact from the transit of an LNG vessel on an average of once per week.

#### 4.8.2.4.1 LNG Terminal

As noted above, tourism in the project area is not a large contributor to the state or local economy. However, tourism-type activities in both Maine and Canada remain an important part of the area’s amenities, with many residents taking part in many of the same activities as tourists, especially boating recreation, hunting, shopping, dining out, and local festivals and other events.

During construction, Downeast would mitigate interruption to local businesses by maintaining access to side roads and business entries. Local concerns about construction activity and possible impacts on local businesses primarily focus on the reaction of possible shoppers if large numbers of construction vehicles on U.S. Route 1 cause delay of traffic. In particular, it is believed that potential customers would not consider getting off the road to come into a roadside business.

Traffic studies conducted for Downeast indicate that, with proper planning and mitigation measures, the construction of the project would not result in significant traffic delays or stoppages (see section 4.9 for further information on transportation and traffic). State and local road cut permits may also include measures to mitigate the impact of traffic caused by construction.

No major recreational activities occur at the proposed pier location. The proposed pier is over 3,000 feet from the currently used vessel channel, providing more than sufficient access for vessel use. Concerns have been expressed that the visibility of the LNG terminal may affect tourism. The LNG terminal is being constructed so as to have minimal viewshed impacts from the Canadian side of the river, and would not emit smoke or steam. Viewshed changes would have minimal impacts to tourists in both the United States and Canada.

#### 4.8.2.4.2 Sendout Pipeline

Construction of the sendout pipeline could have brief, localized impacts on tourist traffic if construction vehicles caused congestion on local roadways. The mitigation measures discussed in section 4.9 of this EIS would apply to pipeline construction traffic, and impacts during construction would be insignificant. No impacts on tourism are anticipated from the pipeline's operation.

### 4.8.2.5 Fishing Industry

The principal commercial fisheries in the vicinity of the proposed project and the LNG marine traffic route are lobster and herring, clamming, and salmon aquaculture.[21] Combined commercial fishing income for the primary users of Mill Cove is about $19,000 per year at current market prices, including $10,000 from lobstering and $9,000 from herring. Previous income from the local area was substantially higher, principally due to significantly higher yields in the past (Morrison 2006). Washington County had approximately 2,000 active commercial fishermen and approximately $800 million in landings in 2012 (Maine DMR 2012).

Due to the strong currents, commercial fishing within the channel is relatively light. Most of the lobster fishing is conducted in the Grand Manan Channel and along the coast south of Lubec Narrows. Herring is harvested mainly through the use of weirs, active along the coast away from channel traffic, and purse seiners. Aquaculture has been a mainstay industry in the area, with salmon being the principal fish grown and harvested. The state-controlled leases for these facilities are generally along the waterway in shallower water than that transited by deep-draft vessels. Reportedly, on any given day there are approximately 20 small commercial draggers and lobster boats working in the inlets and coves. The regional pilots have estimated that about 20 fishing vessels operate out of the U.S. side, and over 300 licensed fishing vessels from the Canadian side seasonally, but not necessarily all at the same time.

Primarily, the fish catch is lobster and herring, with limited amounts of scallops and other species. There are some shellfish (soft-shell clam) nurseries along the transit route; however, these areas are well inshore where manual harvesting of the clams is accomplished using hand rakes. The shorelines along most of Head Harbour Passage, Friar Roads, and Western Passage are steep and rocky, offering little habitat for the soft-shell clam. The majority of the remaining area that would provide the necessary habitat is adversely affected by the "red tide," a "bloom" of damaging marine microorganisms; only a few of the coves/mud flats are actually open to shellfish harvesting. Scallops are harvested commercially by draggers, primarily in Cobscook Bay and South Bay, which are south and west of the transit route and proposed facility site.

The 2012 Maine-wide landed values for lobster was $521.5 million. Lobster landings along the Maine coast have, with only a few exceptions, generally risen since the late 1980s with 126 million pounds in 2012, of which 21 million pounds (16.7 percent) were landed in Washington County (Maine DMR 2012). Most lobsters landed in Washington County are

[21] There are no official Maine state lobster or herring landing records specifically for Passamaquoddy Bay. The Canada Department of Fisheries and Oceans does not separate Passamaquoddy Bay catch data in its New Brunswick/Bay of Fundy area reporting, either for lobster or herring. Downeast LNG therefore focused on the Maine data that includes a breakdown to the county level for lobsters. Mr. Dave Libby, Marine Resources Scientist at the Maine Department of Marine Resources, assisted in providing an historical synopsis of the herring industry. Downeast collected additional data by interviewing local fishermen.

caught along and offshore of the outer coast, with substantially fewer traps set inside of West Quoddy Point in Cobscook Bay, Western Passage, and Passamaquoddy Bay, due in large part to the strong tidal currents, which can present difficulties in setting and hauling traps. The reported current landed value of $10,000 for lobsters (roughly 2,000 to 3,000 lbs.) caught in the vicinity of Mill Cove represents a tiny fraction of the county's total.

The herring fishery is the most important pelagic fishery resource in Maine. Harvest numbers for the years provided by the Mill Cove weir owner are generally consistent with those posted by the Maine DMR. Herring canneries have all but disappeared in Maine, but continue to operate on Passamaquoddy Bay in New Brunswick, Canada. In comparison to the proposed project vicinity data, the 2012 Maine-wide landed values were $14.5 million for herring (Maine DMR 2012). In Maine, herring catch data is only reported on a statewide basis (Libby 2006; Maine Commercial Marine Fisheries 2006).

According to the Maine DMR, farm-raised finfish harvest in Maine yielded 24.4 million pounds of Atlantic Salmon with a value of $73.6 million in 2010. The harvest totals vary greatly from year to year, with, for example, 11.6 million pounds and $23.2 million in 2005, 36 million pounds and $79 million in 2000, 22 million pounds and $56.3 million in 1995 (Maine DMR 2013). As of spring 2013, there were 26 active finfish aquaculture leases in Maine, 13 of which are in the Cobscook Bay area. There are four salmon aquaculture sites belonging to Cooke Aquaculture on the Maine side of the border in the vicinity of Eastport near the transit route to the Downeast LNG Project pier. All four sites are north of the Eastport breakwater and Dog's Head. In New Brunswick, there are eight marine farms near the LNG marine traffic route.

Aquaculture activities directly account for more than 3,000 full-time jobs (25% of the workforce) in New Brunswick's Passamaquoddy Bay region. Total direct employment wages, salaries, and benefits expenditures are estimated at $47 million. Aquaculture supports an estimated 2,900 jobs with a total payroll of $46 million in related supply and service industries such as boat building, net and cage manufacturing, and machine shops. The island of Grand Manan alone has approximately 240 direct and indirect full time, year round jobs related to the salmon farming industry. A 30 percent growth in aquaculture employment is projected to occur on the island of Grand Manan over the next few years, resulting in 73 new jobs and an additional $1.3 million in wages. New Brunswick collects more than $4.5 million in tax revenues from the farming industry on Grand Manan each year (Boucher 2013).

#### 4.8.2.5.1 Waterway for LNG Marine Traffic

Downeast has proposed two transit routes for LNG vessels to and from the proposed LNG terminal. LNG vessels bound for Passamaquoddy Bay can either (1) enter the Gulf of Maine and transit up the Grand Manan Channel on the westerly side of Grand Manan Island to Head Harbour Passage or (2) enter the Grand Manan Basin and transit up the Bay of Fundy VTS on the easterly side of Grand Manan Island. According to the WSR, either route is acceptable to the Coast Guard. Safety and security zones would be established around transiting LNG tankers. Local fishing vessels operate within set seasons but are unable to plan in advance when they would be within the proposed LNG tanker route because the fishermen are opportunistic in that their use of the waterway is influenced by weather and the location of fish stocks. Particularly in areas of high current like Head Harbour Passage and the Grand Manan Channel, fishing typically occurs at slack tide when tankers would also travel though the waterway (Boucher 2013). Consultations with local fishermen conducted by Downeast indicate that in general fishermen try to avoid placing fishing gear directly in designated shipping lanes in order to prevent loss of their equipment. However, because there is no designated shipping lane within the Grand Manan Channel or Western Passage, it is likely that LNG tankers could interact with fishing gear along these routes, causing lobster or crab traps and lines to become entangled and damaged by passing vessels, causing fishermen to lose gear and income and inadvertently killing lobsters and other species. Lost lobster and crab gear and halibut longline gear also pose an entanglement danger to whales (Boucher 2013).

Downeast has developed a comprehensive compensation plan to address any potential loss of fishing equipment or income as a result of unavoidable impacts by Downeast LNG vessels. This Fishermen's Communication, Coordination, and Compensation Plan includes replacement cost payment for traps or gear loss, plans to maintain a stock of traps and gear for immediate replacement of lost or damaged equipment, coordination with local suppliers to ensure adequate stocks of equipment, and coordination with Maine DMR and lobstermen to ensure tag replacement, if necessary. Downeast intends to implement the following measures to avoid impacts on fishing equipment: (1) During the peak fishing season (June-July, September-October), as few as three vessels per month would transit the area; (2) Downeast has proposed transit routes that, subject to the discretion of the pilot and vessel captain, would avoid lobster waters during this peak season, reflecting input from several lobstermen; (3) Downeast would implement a "Look Ahead" lobster trap survey before and after each LNG vessel transit; and (4) Advance mariner advisories would publish LNG transit dates and times. Downeast consulted with individual members of the Cobscook Bay Fishermen's Association, the Campobello Fishermen's Association, and other sources to develop this Communication, Coordination, and Compensation Plan to reduce adverse impacts on commercial fishing, which applies to both U.S. and Canadian fisheries that occur within the waterway from the pilot boarding area in the vicinity of East Quoddy Head to the LNG terminal.

Downeast contracted with Dr. Porter Hoagland and Dr. Di Jin, who are associated with the Marine Policy Center of the Woods Hole Oceanographic Institution, to independently assess the potential economic impact on lobstering that might be associated with the proposed facility. Based on conservative assumptions (favoring the lobster fishery), Hoagland and Jin concluded that significant economic impacts from LNG vessel transits would be unlikely. Regardless, Downeast would continue discussions with lobstermen as well as fishermen to finalize any potential compensation and mitigation planning measures that may be appropriate. We have included a recommendation in section 4.5.2.2 for Downeast to continue consultation with NOAA Fisheries, Maine DMR, and other appropriate agencies to finalize its Fishermen Communication, Coordination, and Compensation Plan.

There is no indication that the LNG project would affect any lobster catch results in Canada, as there is little if any lobstering along the LNG vessel route in the waters of Head Harbour Passage. There are no salmon aquaculture pens directly within the LNG marine traffic route; however, boats servicing the aquaculture sites use the same waterway as the proposed LNG vessel transit route.

#### 4.8.2.5.2 LNG Terminal

Construction activities associated with the pier would last approximately 20 months and include the installation of the pier structure support piles and surface platforms. Noise from pile driving associated with the pier construction could discourage recreational fishing in the immediate vicinity. Given the low use of the area for such purposes and the large amount of alternative areas for recreational fishing, this impact is expected to be insignificant.

There would be little if any perceptible impact on estuaries or lobster breeding grounds in Mill Cove or at other locations as a result of the pier construction. Potential effects to lobster populations and habitat are discussed in section 4.5 of this EIS.

The proposed project would not have a significant adverse impact on the lobster fisheries. However, the two residents of Robbinston who are reported to be the primary lobstermen for this area may be potentially adversely affected due to the construction and operation of the project pier. It is uncertain if the lobstermen could continue to lay traps and recover them without line entanglement around the pier. Downeast has developed a Fishermen Communication, Coordination, and Compensation Plan to address impacts on lobster gear that may result with the implementation of its LNG project. This would not affect the area's overall fishery income, since these lobsters could be caught in other nearby areas. Downeast in cooperation with the Maine DMR has met with leading representatives of the local lobster fishery to further define and detail the lobstermen's key concerns. This information would be used in Downeast's ongoing effort to update and revise the original Fishermen Communication, Coordination, and Compensation Plan.

There is very limited fishing in the pier area that would be affected. However, the existing Mill Cove weir fishing practices would be directly affected by noise, lighting, and other activities during the construction and operation of the project pier, which would bisect the area used by the weir fishermen to drive fish into the weir and eliminate the use of the weir during the project life. While there are over 100 herring weir locations along the coast of Maine, the loss of use of the weir system in Mill Cove would have a direct economic impact upon the weir owners. At current value and productivity, the annual economic loss from non-use of the weirs would equal roughly $9,000 per year, although the area's overall fishery income may not be affected, as the herring may be caught in other area weirs beyond Mill Cove. The Mill Cove weirs have operated intermittently and have been of minimal value in the last decade. Downeast has negotiated an agreement with the weir owner to compensate for the losses resulting from the operations of the LNG facilities. No other fishing weirs would be affected by project operations. Revisions to the Fishermen Communication, Coordination, and Compensation Plan are ongoing, and we have recommended that Downeast file the final Plan with the Commission prior to operation of the LNG terminal.

Shoreline fishing and clamming from the immediate vicinity of the LNG terminal site may be prohibited when an LNG vessel is docked based on the 500-yard fixed safety and security zone that could be established around the moored vessel. It has not been determined if a safety/security zone would be established around the pier when an LNG vessel is not present. According to local community members and observations during the course of Downeast studies of the area, there is no shoreline fishing along south Mill Cove or its vicinity, and very little clamming activity. The vast majority of clammers observed in Mill Cove were digging the north and central Mill Cove muds. This is likely due to the fact that the tidal substrate coincident with clams is not predominant at the shoreline area of the Downeast LNG Project pier. While the exact area of prohibited activities near the project pier has not yet been determined, it would be included by Downeast in its Operations and Emergency Manuals and Facility Security Plan. In accordance with 33 CFR Part 127.019, Downeast must submit two copies of the Operations and Emergency Manual to the Coast Guard COTP Sector Northern New England for review and approval at least 30 days before transferring. Furthermore, in accordance with 33 CFR Part 105.410, Downeast must submit the Facility Security Plan to the Coast Guard COTP Sector Northern New England at least 60 days in advance. This is reiterated in section 4.6, Risk Mitigation Measures, of the Coast Guard's WSR (Appendix B). The prohibition of shoreline fishing or clamming in the less active immediate vicinity of the project's pier abutment with the shore is not anticipated to be a significant adverse impact.

#### 4.8.2.5.3 Sendout Pipeline

Construction of the sendout pipeline would have minimal effects to commercial and recreational fishing. Any disruption of fishing activity along inland streams during pipeline construction would be very localized and short-term. Operation of the pipeline would have no impacts on fishing.

### 4.8.2.6 Agricultural Industries

Washington County is a predominately rural area, with substantial agricultural and forestry resources.

#### 4.8.2.6.1 LNG Terminal

There are no agricultural lands in the immediate vicinity of the LNG terminal site; therefore, no agricultural lands would be affected by the construction and operation of the LNG terminal.

#### 4.8.2.6.2 Sendout Pipeline

Construction of the sendout pipeline would impact about 2.1 acres of agricultural land, with about 1.3 acres to be included in the permanent pipeline right-of-way. Agricultural uses would be impacted during construction, but would be allowed to continue following construction. Due to the temporary and short-term nature of impacts on agricultural uses, it is expected that the impact on the agricultural industry would be minimal. Construction and operation of the sendout pipeline could result in long-term impacts on forest areas, as a permanent right-of-way would be cleared and not allowed to revert to forest or be used for timber production during the pipeline's operational life (see section 4.7 of this EIS). Compensation for the temporary or permanent loss of any timber production would be addressed during easement negotiations between Downeast and affected landowners. Because landowners would be compensated for any losses that might result, economic effects would be insignificant.

## 4.8.3 Housing

There were 23,001 housing units in Washington County in 2010; over 11 percent were mobile homes (USCB 2010). Of the total housing units, 14,302 (62.2 percent) were occupied and 8,699 (37.8 percent) were vacant. Of the vacant housing units, 6,329 (72.8 percent) were for seasonal, recreational, or occasional use, resulting in 2,370 units classified as year-round housing. The median value for owner-occupied units was $68,700. The median gross monthly rent for renter-occupied units was $419. In addition to the housing stock, there are 23 hotels/motels in Washington County (Podunk County Profiles 2006).

The Town of Robbinston had 354 housing units at an average density of 12.6 per square mile. Of these units, 238 (67.2 percent) were reportedly occupied (57 percent owner-occupied and 10.2 percent renter-occupied). Robbinston had a higher percentage of owner-occupied housing units than Washington County (46.9 percent) and the State of Maine (55.1 percent). Twentyfour percent of the housing units were for seasonal, recreational, or occasional use. The proportion of housing units that are for these uses is higher in Robbinston than in the state as a whole (16.4 percent).

The median value for owner-occupied units in the Town of Robbinston was $129,200. This is comparable to the median home value in Washington County ($102,300) and the state as a whole ($176,200). In the Town of Robbinston 14.6 percent of the owner-occupied housing units were valued at less than $50,000, and 28.6 percent were valued between $50,000 and $100,000. Only 10 percent of these homes were valued over $500,000. The median gross monthly rent for renter-occupied units was $545, higher than the county ($496) but lower than the state ($707).

Based on a summer 2006 field survey and review of aerial photographs, there were approximately 50 houses within a 1-mile radius of the project entrance, primarily along U.S. Route 1, Ridge Road, and in the Mill Cove area north of the site.

The 2010 census reported that Robbinston had 116 vacant houses and a vacancy rate of 32.8 percent, higher than the state and higher than the county. Table 4.8.3-1 provides total housing unit data for the project area.

TABLE 4.8.3-1

**Number and Density of Housing Units in the Project Area**

| Community | Number of Housing Units | Density of Housing Units (Units per Square Mile) |
|---|---|---|
| Robbinston | 354 | 12.6 |
| Alexander | 399 | 9.9 |
| Baileyville | 875 | 23.6 |
| Baring Plantation | 141 | 6.7 |
| Calais | 1,737 | 50.6 |
| Charlotte | 256 | 8.3 |
| Cooper | 167 | 5.4 |
| Eastport | 1,083 | 298.3 |
| Meddybemps | 182 | 13.9 |
| Pembroke | 531 | 19.4 |
| Perry | 551 | 18.8 |

Source: USCB 2010

### 4.8.3.1 LNG Terminal

Construction and operation of the terminal would have a minimal impact on local housing markets through the influx of workers, because nearly all of the workers hired are anticipated to live in homes within commuting distance or other available accommodations, such as local hotels, motels, cabins, and campgrounds. The use of these alternative accommodations would assist the project area in moderating seasonal fluctuations in normal occupancy (i.e., high summer occupancy, low winter occupancy). While there are discrepancies between census data and local realtor estimates, it is expected that non-local workers would be able to find temporary housing in the local area.

There are no residences or businesses on the terminal site and hence no displacement would occur as a result of construction or operation of the facility. During the operations phase, the terminal facilities would employ 78 workers, many of whom are expected to be hired from among local residents. Any employees relocating to the area would be able to find permanent housing in the area, either in existing housing or in new housing being developed independent of the project. Even assuming conservatively that all workers relocated to the area with their families, the impact would be insignificant in the project area, which has sufficient available housing units to support the newcomers.

#### 4.8.3.2 Sendout Pipeline

Construction of the sendout pipeline is expected to last approximately nine months. Most short-term construction workers who do not live in a project area typically prefer temporary quarters such as hotels, motels, rental housing, or rented rooms from local residents, while the remainder may utilize campsites and recreational vehicle sites. Impacts on the local housing market would be insignificant.

During operation of the sendout pipeline, negligible impacts on local housing markets would be expected, since only four permanent staff would be required to manage its operation and maintenance. No homes or businesses would be displaced by construction of the pipeline.

### 4.8.4 Tax Revenues

Washington County's approved 2013 budget was $5,792,431 (Down East 2013, Walsh 2012). Local taxes are collected by the Town of Robbinston. Local taxes include a Washington County tax and a school district tax. For 2010, the property taxation rate in Robbinston was 11.05 percent per $1,000 of assessed value (State of Maine 2010).

There would be no direct impact on tax revenues from the LNG marine traffic along the waterway.

#### 4.8.4.1 LNG Terminal

LNG terminal activities would affect the state government through increased corporate and income tax revenues and additional sales tax receipts. The county and municipalities would receive increased property taxes.

The University of Maine study included a fiscal impact analysis based on Maine's current tax and educational spending system, using data from 2004 and 2005. The study found that those workers directly and indirectly associated with construction and tugboat manufacturing would pay an estimated $1.4 million in state personal income taxes per year in each of three years of pre-operations activities. The direct and indirect economic activity, including business and household spending by those associated with project construction and tugboat manufacturing, would generate an estimated $1.3 million in sales taxes during each of the three years that construction is taking place (University of Maine 2005).

Based on Maine's 2005 maximum state corporate income tax rate of 8.93 percent and Downeast's anticipated earnings, Downeast would contribute approximately $625,000 to $1.8 million in corporate income taxes annually (University of Maine 2005). Workers directly and indirectly supported by the Downeast LNG Project would pay $539,268 in state personal income taxes annually over the lifecycle of the terminal, expected to be 30 years or longer. Finally, the economic activity associated with operations (e.g., business and household spending by those directly and indirectly associated with facility operation) would generate an estimated $246,282 in state sales tax revenue per year.

The University of Maine study found that the presence of a $400 million LNG terminal in Robbinston would lower the Town of Robbinston's full value tax rate by 69.1 percent. The study estimated that Downeast would pay $1.2 million in local property taxes on an annual basis once the terminal is in operation, amounting to 92.1 percent of the total property taxes paid in the Town of Robbinston.

Construction and operation of the project would also affect municipal expenditures and the size of the local tax base. In addition to an anticipated increase in the local tax base, several other fiscal impacts can be anticipated relative to local government expenditures and revenues. These impacts include changes in Robbinston's county tax obligations and possible reductions in educational subsidies and funding from revenue sharing (University of Maine 2005).

The anticipated construction cost of the facility is $400 million. At this value, the terminal would increase the 2006 full state value of real and personal property from $33.05 million to $433.05 million, leading to a decrease in the local full value property tax rate (University of Maine 2005). This increase in the local tax base would increase the amount of taxes paid by Robbinston to the Washington County government. Robbinston has a 2005 state valuation of $30.95 million, which results in obligation to pay $55,097 to Washington County. The Downeast LNG Project could lead to a $400 million increase in total state valuation, resulting in a decrease in Washington County's full state value tax rate from 0.00178 to 0.00153. According to the University of Maine 2005 study, Robbinston's tax obligation to Washington County would be expected to increase by $602,136 to $657,233 as a result of operation.

An increase in the Robbinston tax base may also result in reduction in the amount of educational subsidies Robbinston receives from the state, as the subsidies are linked to Robbinston's full state valuation. A $400 million increase in Robbinston's state valuation could decrease the educational subsidy from the currently anticipated value of $454,603 (estimated for 2005-2006 school year) to $95,293, a decrease of $359,310 if the project were operational in 2006 (University of Maine 2005).

The amount of funding received by Robbinston through state and municipal revenue sharing could also be affected by operation of the LNG facility. The $400 million increase to the full state value of real and personal property and other estimated changes to local government expenditures and revenues would lower Robbinston's allotment of the revenue sharing distribution by an estimated $19,611, from $27,295 to $7,684 (University of Maine 2005).

The fiscal impacts described above could increase Robbinston's total expenditures from $302,944 to approximately $1.3 million. Combined with a $400 million increase in the full state value of real and personal property, this would lead to a reduction in the full state value property tax rate from 0.0097 to 0.0030, assuming no new development and no increase in expenditures on local public services. This rate reduction would benefit Robbinston homeowners and businesses by lowering their property taxes. Operation of the LNG facility would obligate the facility to pay $1.2 million in annual local property taxes to Robbinston, equivalent to approximately 92 percent of the total property taxes paid in the municipality (University of Maine 2005). The reduction in revenues paid to the county and town by the state would also result in a beneficial impact on Maine taxpayers outside of Washington County.

In the Host Community Benefits Agreement, Downeast has agreed to pay its property tax obligation to the town based upon the assessed (fair market value) of the project, without deduction for plant depreciation or amortization, as calculated by the town in accordance with applicable laws. In order to secure the payment obligation, Downeast has agreed to obtain and maintain in effect a bond, letter of credit or other form of security in favor of the town covering three full years of estimated property tax obligations.

Under the Host Community Benefits Agreement, Downeast has also agreed to establish a community development fund exclusively in the name of the town, to which it would initially contribute the sum of $100,000 per calendar year (increased to annual payment of $1.2 million per calendar year at start of operations). The fund would be administered by a group of town residents, specifically responsible for the management of such funds. Downeast has placed no restrictions on the use of the Community Development Fund.

Under the Agreement, Downeast has also agreed to reimburse the town for the reasonable expense of hiring a part-time clerk or other qualified official to ensure that the project complies with all applicable licenses, permits, approvals, laws and regulations. Downeast has further agreed to put into place and to maintain a form of financial security in an amount sufficient to fund the estimated costs of decommissioning and dismantling facilities at the conclusion of its scheduled operational life in accordance with the requirements of applicable federal and state laws, regulations, licenses, permits and approvals. The amount of the financial security instrument would be revised no less frequently than every five years in order to keep pace with changes in the estimated costs of decommissioning and dismantling the project.

#### 4.8.4.2 Sendout Pipeline

Construction and operation of the sendout pipeline would also generate county and town tax revenues. Based on preliminary information and review of tax revenues generated by the existing M&NE pipeline, as well as the Portland Pipeline (est. 1999, used for Maine state tax calculations), the following analyses have been made to develop tax revenue estimations. It has been assumed for this assessment that the tax valuation of the pipeline would be calculated in a manner similar to previous tax formulations used for gas pipelines in unorganized territories of Maine, i.e., that the valuation used for the Downeast sendout pipeline would be based on a construction cost of approximately $1.0 million to $1.2 million per mile. The pipeline distance is approximately 29.8 miles.

At the lower value ($1.0 million/mile), the total real property tax valuation would equal $29.5 million, while the higher value ($1.2 million/mile) yields an estimate of $35.4 million. This value would be taxed in full by each town in Year 1. The valuation would then be depreciated 2.0 percent per year for Years 2-5, and then 1.5 percent per year for Year 6 and beyond. Estimates based on the more conservative values (at $1 million per mile) are shown in table 4.8.4.2-1.[22]

In addition to the individual townships, Washington County would benefit from the tax revenues generated by the sendout pipeline. However, the county's tax revenue would be dependent on each town's respective mill rate differential after the construction of the sendout pipeline has been completed. Since this is not known at present, an amount equal to 10 percent of each town's tax revenue from the sendout pipeline has been assigned to Washington County for general estimation purposes. As such, the Year 1 tax revenues generated by the sendout pipeline

[22] Note: The University of Maine Study used the higher value, $1.2 million per mile, in its estimations.

for Washington County would approximate $56,276 [at the more conservative estimate of $1.0 million per mile of pipeline]. The total annual amount would be reduced each year thereafter due to depreciation.

TABLE 4.8.4.2-1

**Estimated Property Tax Revenues from Sendout Pipeline for Year 1**

| Township | Pipeline Miles | Total Value | Millage Rate | Tax Revenue |
|---|---|---|---|---|
| Robbinston | 4.7 | $ 4,700,000 | 0.0136 | $ 63,920 |
| Baileyville | 10.7 | 10,700,000 | 0.0150 | $160,500 |
| Baring | 2.7 | 2,700,000 | 0.0162 | 43,740 |
| Calais | 10.5 | 10,500,000 | 0.0260 | $273,000 |
| Princeton | 1.2 | 1,200,000 | 0.0180 | 21,600 |
| **Total** | **29.8** | **$29,800,000** | | **$562,760** |
| **Washington County (estimated to be 10% of total revenues)** | | | | **$56,276** |

The State of Maine would not receive direct tax revenues generated by the sendout pipeline's real property value. However, as noted earlier, the reduction in state payments to the county and municipalities would result in a beneficial impact on Maine taxpayers and residents outside of Washington County.

## 4.8.5 Public Services and Infrastructure

### 4.8.5.1 Schools

The 11 communities of eastern Washington County (including Robbinston) have a total of 8 public elementary schools and 3 high schools within 3 school districts. Information regarding student enrollment at area schools is shown in table 4.8.5.1-1. The excess capacities in area schools (except for Perry) reflect declining population trends over past decades.

Post secondary schools located in eastern Washington County include the University of Maine–Machias and Washington County Community College (Calais and Eastport campuses).

#### 4.8.5.1.1 LNG Terminal

Area schools could see a small increase in enrollments as a result of the influx of construction workers. However, this would not be a significant impact on local schools for several reasons. First, except for Perry's elementary school, all schools have sufficient capacity to absorb sizable increases in enrollment. Second, it is likely that new pupils would be distributed among several schools, rather than concentrated in one or two facilities. Finally, it is assumed that many of the construction workers would be area residents, so their children would already be in local schools. Therefore, adverse impacts to area schools would be minimal.

TABLE 4.8.5.1-1

**Enrollment and Capacity in Project Area Schools**

| School | Enrollment | Capacity | Enrollment as % of Capacity | Source |
|---|---|---|---|---|
| **Elementary (Grade) Schools** | | | | |
| Robbinston | 51 | 100 | 15% | Maine Department of Education Data Center; Public School Review 2013 |
| Calais | 284 | 384 | 74% | Perkins, 2006; Public School Review 2013 |
| Charlotte | 41 | 75 | 54.7% | Lingley, 2006; Public School Review 2013 |
| Eastport | 85 | 300 | 28.3% | Eastport Elementary School Secretary, 2006; Public School Review 2013 |
| Pembroke | 101 | 150 | 67.3% | Pembroke Elementary School Secretary, 2006; Public School Review 2013 |
| Perry | 107 | 120 | 89.2% | Smith, 2006; Public School Review 2013 |
| **High Schools** | | | | |
| Calais | 367 | 450 | 81.6% | Underwood, 2006; Public School Review 2013 |
| Shead, Eastport | 119 | 250 | 47.6% | Stanhope, V., 2006; Public School Review 2013 |
| Washington Academy, Machias (private) | 390 | 520 | 75% | McBrine, 2006 ; Private School Review 2013 |

Under the Host Community Benefits Agreement, Downeast would fund the construction of a new elementary school within the town (at an estimated cost, including land acquisition, of $5 million) to replace the existing school. The draft Host Community Benefits Agreement anticipates that the school would be operational by the start of project operations and be designed at a size that meets the reasonable projected growth in school population.

#### 4.8.5.1.2 Sendout Pipeline

As discussed above, few families are expected to relocate to the project area during construction of the pipeline. Therefore, no impacts on existing public services and infrastructure are anticipated from construction and operation of the pipeline.

### 4.8.5.2 Police, Fire, and Emergency Services

The Town of Robbinston has no police force. Depending on the circumstances, law enforcement services are provided by either the Washington County Sheriff's Office or the Maine State Police. The Sheriff's Office has six full-time patrol offices assigned to northern, central, and western divisions of the county. The department also has two officers contracted to the Town of Lubec and one to the Town of Jonesport, along with a K-9 unit and administrative staff (Washington County Sheriff's Office Website 2008). Troop J of the Maine State Police has a total of 25 troopers in Washington County. Tactical, Air, Dive, Hostage, and Bomb Teams from other areas are also available in emergencies (Snedeker 2006).

Fire emergencies in the Downeast LNG Project area are responded to by a collaboration of fire departments from the towns of Robbinston, Charlotte, Perry, Pleasant Point, Eastport, and the City of Calais. Safety and emergency response are discussed in section 4.12 of this EIS.

The majority of local, on-site public and private emergency response services within the immediate area are predicated on ‘everyday’ emergent situations based on a largely rural population and risk model. In the event of a large-scale crisis or catastrophe, the implementation of enhanced response capabilities, such as bomb squads, hazardous materials response, marine firefighting/salvage operations, and major medical assistance, etc., would require significant coordination among the major emergency organizations.

#### 4.8.5.2.1 LNG Terminal

The influx of workers to construct the LNG facility could increase the costs of public safety services, and facility operations could place demands exceeding the capacity of the existing infrastructure. Under the Host Community Benefits Agreement, Downeast has agreed to pay the town for all capital costs (estimated at $500,000) associated with the maintenance, improvement or expansion of the firehouse facility and the fire equipment of the town arising out of increased need, due to the operation of the Downeast LNG Project. The annual operating expenses of the town’s fire and emergency services would be included in the town budget.

The development of an ERP, pursuant to Section 311 of the EPAct of 2005, is one of the risk mitigation measures recommended by the Coast Guard’s WSR. In addition, the EPAct calls for a cost-sharing plan identifying the mechanisms for funding all project-specific security costs and safety/emergency management costs that would be imposed on state and local agencies. This cost-sharing plan must specify what the LNG terminal operator would provide to cover the cost of state and local resources required to manage the security of the terminal and vessels. The ERP would be developed through a transparent, public process that actively involves the Coast Guard, appropriate agencies, and key officials of state and local governments.

#### 4.8.5.2.2 Sendout Pipeline

There would be minimal impacts on local public safety services as a result of the construction and operation of the proposed sendout pipeline.

### 4.8.5.3 Medical Services

Two medical facilities serve the proposed Downeast LNG Project area, the Calais Regional Hospital, located approximately 15 miles from the terminal site, and the Downeast Community Hospital in Machias, located approximately 36 miles from the terminal site. As discussed in section 4.8.5.2, a large-scale catastrophe in this remote, rural area would require significant coordination among the major emergency organizations. The potential impacts on medical services from a large scale emergency are discussed below. Medical services would not be affected by normal LNG vessel traffic.

#### 4.8.5.3.1 LNG Terminal

Workers engaged in construction activities for the terminal facilities would likely increase demand for medical services in the project area. However, local hospitals and providers have adequate facilities to handle most emergencies and routine care. In the unlikely event of a large-scale emergency, hospitals and emergency services in the region could address any needs through coordination. Therefore, impacts on local medical facilities would be insignificant.

Operations personnel and their families would constitute a very small increase in the area's population. Impacts on local medical services would be similarly insignificant but probably smaller than those under the construction phase.

#### 4.8.5.3.2 Sendout Pipeline

Pipeline construction workers could increase demand for medical services, but the local facilities are adequate to handle such emergencies and routine care. Impacts on local facilities would be insignificant.

### 4.8.6 Environmental Justice

Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, was signed by the President in 1994. It requires that each federal agency address the potential for disproportionately high and adverse health or environmental effects of its programs, policies, and activities on minority populations and low-income populations. An environmental justice area is defined as an area where the community's minority population is equal to or greater than 50 percent of the community population and/or a community in which the percentage of persons living below the poverty level is higher than the county average, based on poverty statistics published by the USCB. If the proposed action would result in significant adverse effects to minority or low-income populations or Native American tribes, the NEPA analysis should address those impacts as part of the alternatives analysis and identify appropriate mitigation measures to address the effects.

Each federal agency must also ensure that public documents, notices, and hearings are readily available and accessible to the public. As part of the preparation of this EIS, the NEPA review process must provide opportunities for effective community participation and involve consultation with affected communities. Consultation with Native American groups, including the Passamaquoddy tribe, and evaluation of measures to address impacts on that community is described in section 4.10 of this EIS.

This section evaluates the construction and operation of the proposed project to determine if it would have a disproportionately adverse impact on minority or low-income populations. The assessment follows the methodology in EPA's *Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses* (April 1998).

As noted earlier, the socioeconomic impact area for the proposed project is Washington County. Table 4.8.6-1 provides data on minority population and income for all communities affected by the proposed project, along with data on comparison areas.[23]

In 1999, 19.9 percent of the county's population lived below poverty level, while the state of Maine had a poverty rate of 12.6 percent and the United States, 13.8 percent. As of 2010, the county's population was 92.1 percent white (Caucasian) and 4.9 percent Native American, with other groups comprising only 3.0 percent of the total. Hispanics, who can be of any race, were 1.4 percent of total residents (USCB 2010).

[23] Data from the 2000 Census are the latest reliable and consistent data regarding the ethnic composition and poverty status of the population, especially for sub-county divisions such as towns or census tracts. Later estimates from varying sources may use different methodologies and do not provide accurate comparisons among areas.

TABLE 4.8.6-1

**Ethnic and Poverty Statistics, Proposed Project Area and Comparison Areas**

| Area | Percent of Total Population | | | | | | |
|---|---|---|---|---|---|---|---|
| | White | Black a/ | Native American b/ | Other Minorities c/ | Hispanic d/ | Per Capita Income | % Below Poverty |
| United States | 72.4 | 12.6 | 0.9 | 14.1 | 16.3 | $27,334 | 13.8 |
| Maine | 95.2 | 1.2 | 0.6 | 2.9 | 1.3 | $25,385 | 12.6 |
| Washington County | 92.1 | 0.4 | 4.9 | 2.6 | 1.4 | $19,401 | 19.8 |
| Town of Robbinston | 98.6 | 0.2 | 2.3 | 1.6 | 0.3 | $18,112 | 21.5 |
| Alexander | 98.2 | 0.0 | 1.0 | 0.8 | 1.2 | $31,631 | 2.3 |
| Baileyville | 98.1 | 0.7 | 0.8 | 3.8 | 0.7 | $25,121 | 9.2 |
| Baring Plantation | 97.2 | 0.0 | 0.0 | 2.8 | 1.2 | $17,359 | 24.4 |
| Calais | 95.5 | 0.5 | 1.3 | 2.7 | 1.4 | $22,127 | 16.9 |
| Charlotte | 94.0 | 0.0 | 3.0 | 3.0 | 0.9 | $21,909 | 8.0 |
| Cooper | 98.1 | 0.6 | 1.3 | 0.0 | 0.6 | $29,316 | 6.9 |
| Eastport | 92.0 | 0.8 | 3.6 | 3.7 | 0.9 | $21,360 | 19.4 |
| Meddybemps | 99.4 | 0.0 | 0.0 | 0.6 | 0.0 | $14,840 | 23.5 |
| Pembroke | 94.9 | 0.1 | 1.3 | 3.7 | 1.0 | $18,303 | 19.1 |
| Perry | 85.5 | 0.2 | 10.5 | 5.0 | 1.0 | $15,416 | 24.6 |
| Pleasant Point Res. e/ | 13.1 | 0.5 | 81.8 | 4.0 | 2.0 | $10,863 | 45.0 |

a/ Black or African American.
b/ American Indian and Alaska Native.
c/ Includes Asian; Native Hawaiian or other Pacific Islander; Some Other Race; and Two or More Races.
d/ Hispanic can be of any race.
e/ Pleasant Point Reservation is a separate "Census Place" not included in the statistics for the Town of Perry.
Source: USCB 2000 Census of Population and Housing, Demographic Profiles.

### 4.8.6.1 LNG Terminal

In the proposed terminal area, the poverty rate in 2010 for the Town of Robbinston was 21.5 percent, substantially higher than the county and the nation, while the population was more than 98 percent white, with a smaller percentage of minorities than the county and comparable to most other communities in the project area. The exceptions are the nearby Pleasant Point Reservation and the Town of Perry, which are approximately 82 percent and 11 percent Native American, respectively. Additionally, on the Pleasant Point Reservation, 45 percent of the population lived below the poverty level in 2010. These two communities would therefore be classified as environmental justice communities, although they are sufficiently distant from the proposed Downeast LNG facility that direct adverse impacts would be highly unlikely. Rather, the proposed project would result in a substantial economic benefit to the neighboring environmental justice communities through increased job opportunities, income, and tax revenues.

The EPA and CEQ provide guidance on assessing environmental justice impacts. This guidance requires that in environmental justice areas, the applicant show, through environmental assessments or environmental impact statements, that there would be no significant impacts as a result of the project, especially in terms of cumulative impacts from the project combined with other sources of pollution in the area that may affect those living there (EPA 1998; CEQ 1997). An analysis of environmental resources, such as surface water, groundwater, and noise, found no significant impacts on the environmental justice communities as a result of the proposed project's construction or operation.

Another important requirement in environmental justice areas is to ensure that members of populations living in these areas are adequately represented, and that they have an opportunity to become involved in development of the proposed project and to express any concerns regarding adverse impacts. NEPA requires that all local residents, not just members of environmental justice communities, be kept advised of the proposed project and allowed to express any concerns. Downeast has held numerous meetings with the local community to explain the proposed project and to determine local concerns. In addition, FERC staff held a scoping meeting in Robbinston; section 2.0 of this EIS provides details of public scoping meetings and community outreach. Section 2.0 also notes that all members of the public, including environmental justice community members, were given an opportunity to file comments on the draft EIS. Our responses to comments received on the draft EIS are included in Appendix S.

#### 4.8.6.2 Sendout Pipeline

The sendout pipeline would traverse the towns of Alexander, Baileyville, Baring Plantation, Calais, Charlotte, Cooper, Eastport, Meddybemps, Pembroke, and Perry. With the exception of Perry, as noted above, all of these towns have very small minority populations. The proportion of the population living below the poverty level varies from 2.4 percent to 20.7 percent, with three communities—Alexander, Baring Plantation, and Pembroke—being slightly higher than the county average. These communities could therefore be defined as environmental justice communities. However, as stated in section 4.8.4 of this EIS, the sendout pipeline operations would substantially increase tax revenues for all of the towns traversed by the pipeline. As a result, both the towns and the environmental justice communities affected by the pipeline would receive significant long-term economic benefits.

Environmental justice considers disproportionate environmental, health, and cultural impacts on environmental justice communities. This EIS analysis found that the pipeline construction and operation would result in minimal potential for air quality impacts, contaminated soils and/or groundwater, or for other environmental or health impacts that could disproportionately affect the local environmental justice communities. Only minimal short-term adverse environmental impacts would occur during construction, and there would be negligible long-term impacts from the pipeline once it is in operation. There would be no disproportionate adverse environmental and human health impacts on low-income or minority communities or Native American groups.

## 4.9 TRANSPORTATION AND TRAFFIC

### 4.9.1 Land Transportation

The Downeast LNG terminal site is located eastward of U.S. Route 1, on the southern shores of Mill Cove in the Town of Robbinston, Maine. U.S. Route 1 is the primary transportation corridor in the vicinity of the site, and generally runs parallel to the St. Croix River and Passamaquoddy Bay, connecting the City of Calais to the north with the towns of Perry, Pleasant Point, Eastport, and Machias to the south. The nearest interstate freeway is I-95, approximately 100 miles from Robbinston via U.S. Route 9, which is also known locally as Airline Road. U.S. Route 9 serves as the primary northeast-southwest connector between the terminal site and I-95.

Inland towns are accessible to and from the project site via a number of rural roads that connect to U.S. Route 1, including Ridge Road (access to Perry, Pembroke, and Charlotte) and Lake Road (access to Perry, Pembroke, and Robbinston).

Access to the terminal site would be directly from U.S. Route 1, consisting of a single, combined entrance and exit approximately 0.5 mile south of the intersection with Ridge Road. U.S. Route 1 within the vicinity of the proposed terminal was restructured within the past 15 years and is in excellent condition. Additional resurfacing work along U.S. Route 1 has continued in recent years in the Perry area (Maine DOT 2013). Speed limits vary from 35 to 55 mph. Traffic count surveys conducted along U.S. Route 1 indicate that traffic along the route has not increased in recent years. Traffic loading is very seasonal with summer traffic representing the highest count period (Stanhope, Earle 2006).

Ridge Road located near the terminal site, would provide access for construction equipment to the proposed equipment laydown areas for the terminal construction activity. Ridge Road is 22 feet wide, and the posted speed limit is 45 mph. Ditches, culverts, and hard-topping are in good condition, but the road is narrow with sharp curves in places.

#### 4.9.1.1 LNG Terminal

Work at the terminal site would require the use of approximately 332 workers over the three-year construction period. Approximately 75 percent of these workers would be on-site during peak construction activities. This equates to an average of 249 workers on-site at any one moment in time.

A project-specific traffic capacity analysis in the area of Robbinston, Maine was performed by Downeast in order to: (1) establish the current traffic volumes and roadway level of service; (2) identify the construction and operation-related vehicle trips that would be associated with the Downeast LNG Project; (3) evaluate future roadway levels of service with the addition of construction and facility operational traffic; and (4) make recommendations for ensuring that facility-related traffic would not have an unacceptable impact on area roadways (HNTB 2006). The study results are reported in terms of Level of Service (LOS), a qualitative measure describing operational conditions at a specific traffic location. LOS is based on service measures such as delay and length of vehicular queues. Letters designate each level ranging from A to F where an LOS of A represents the best operating conditions and an LOS of F represents the worst. At signalized intersections, an LOS of D or higher is desired. At intersections without signals, if the LOS classification falls below a D, an evaluation should be made to determine if a traffic signal or turning lanes are required.

Traffic impacts associated with construction and operation of the terminal were estimated for both material delivery and worker transportation. Each trip would actually count as two end-trips – one to and one from the site. For material delivery trips, approximately 75 material deliveries (150 end-trips) would occur per day during peak months. For worker transportation, the travel of an average of 249 construction workers would result in almost 500 daily end-trips (one trip entering in the morning, one trip leaving in the evening) assuming each worker would drive to the construction site each day. However, Downeast proposes to transport workers from dispersed off-site parking areas to the import terminal during construction by van and/or bus to minimize on-site construction parking requirements and worker trips to the construction site. According to the Traffic Study conducted for Downeast, assuming 50 percent are transported in a 40-passenger bus, and the remainder transported in 10-passenger vans, approximately 15 peak hour and 30 non-peak worker trips are assumed (HNTB 2006).

Downeast has not identified specific off-site parking areas that would be used during construction, but has indicated that these areas would be inactive, existing open fields or graveled areas located along U.S. Route 1 near Woodland/Baileyville and Perry/Pembroke. Prior to the use of these areas, Downeast would file the location and environmental information with FERC staff for review and approval.

According to the Traffic Study conducted for Downeast, during operations, the estimated 78 employees would generate 99 end-trips during peak hours and 50 non-peak end-trips. This estimate assumes 75 percent of the employees would arrive and depart during standard morning/evening hours, and an average vehicle occupancy of 1.3, the approximate state average for Maine. Based on this level of trip generation, no State of Maine traffic permit is required. The traffic analysis concluded that the site driveway, U.S. Route 1, and Ridge Road would operate with acceptable LOS levels, given the predicted traffic increases. Other study area intersections are also anticipated to operate at acceptable LOS, based on the minimal existing volume of traffic (HNTB 2006).

The traffic analysis also assessed sight distance and crash data, finding that all locations have sight distances in excess of the minimum Maine DOT recommended guidelines for safe traffic operations, and that there were no high crash locations within the Town of Robbinston. To ensure safe ingress and egress of construction and operations traffic, Downeast proposes to construct turning lanes on both the north and southbound lanes of U.S. Route 1 at the entrance to the terminal site. The construction of these turning lanes would not affect any existing public utilities.

Federal siting regulations for LNG facilities under Title 49, CFR, Parts 193.2007 and 193.2059 have established exclusion zones to ensure adequate separation between members of the public and flammable vapor dispersion. These exclusion zones must be legally controlled by the LNG facility operator or a government agency. Although the 1,600 Btu/hr-ft$^2$ incident flux level for the north storage tank (T-201A) located at the terminal site extends beyond the site property and onto U.S. Route 1, which is under the legal control of the State of Maine, it would meet the requirements specified by Title 49, CFR, Part 193. In the Yukon Pacific LNG Project, the

Department of Transportation, Office of Pipeline Safety (OPS) filed comments with the Commission dated August 9, 1993 indicating that the need for an LNG operator to demonstrate an ability to control public access to property does not apply to transient travel within the exclusion zone, including travel offshore. Downeast, therefore, is not required to control the area of U.S. Route 1 that falls within the exclusion zone, and hence, the thermal radiation exclusion zone for the north tank meets federal code requirements.

Based on the findings discussed above and Downeast's implementation of the mitigation measures discussed below, we believe that construction and operation of the proposed terminal would not significantly affect traffic conditions on roads proximal to the site.

#### 4.9.1.2 Sendout Pipeline

An estimated 320 workers would be employed to construct the sendout pipeline, resulting in over 600 daily end-trips. The pipeline construction crews would be divided into two different spreads. Downeast would implement a bus and vanpool system to transport groups of workers from the off-site leased parking areas, thus reducing the traffic to 40 peak hour end-trips and 80 non-peak end-trips. These end-trips would be split between the two pipeline construction spreads. Additionally, six to seven pipe delivery trips to the storage areas (see table 2.2.2.1-1) are anticipated daily. Only four permanent staff would be required for operation and maintenance of the sendout pipeline.

Limited traffic delays may occur at pipeline-roadway crossing locations. We believe that pipeline construction would not result in a significant increase in traffic volume, and would not adversely affect traffic on area roadways. Downeast has agreed to the mitigation measures described below, which would minimize the impacts and ensure safety for construction crews and roadway passengers.

In the Traffic Study commissioned by Downeast (HNTB 2006), Downeast has agreed to provide a number of traffic mitigations, including:

- provide flaggers as required at driveways to material sites, equipment laydown areas, and the intersection of Ridge Road and U.S. Route 1 during peak construction periods to safely facilitate the movement of trucks and other construction-related vehicles;
- perform daily roadway cleaning, which includes a truck cleaning station/services for all trucks exiting the terminal, pipeline construction, and material storage sites;
- mitigate any construction traffic-related impacts on local and state roadways following construction, including roadway reconstruction and paving, the provision of turning lanes at the facility entrance, and roadway striping and signing; and
- prohibit employee/vendor parking alongside U.S. Route 1 near the terminal site.

The Host Community Benefits Agreement also requires that Downeast pay the cost of repairing any material damage to town or state roads during the construction or operation of the Downeast LNG Project that is directly attributable to construction or operation. Finally, the Traffic Study notes that Downeast would consult with the Maine DOT and the road departments of affected communities regarding the need for improvements that might be identified and deemed necessary in the future, as well as the mitigation measures identified above.

### 4.9.2 Marine Transportation

Downeast has indicated that materials required for construction would be delivered by land, via U.S. Route 1. Marine traffic associated with construction of the terminal would be minimal and limited to the arrival and departure of construction barges and tugs. With coordination and advance notice regarding the construction barges, impacts on fishing vessels, ferries, and other marine traffic would be minimal.

Operation of the LNG terminal would result in regular LNG marine traffic in the Bay of Fundy, Grand Manan Channel, Western Passage, and Passamaquoddy Bay. An LNG vessel's transit from the sea to the Downeast LNG terminal would follow a circuitous route through Canadian waters. This is virtually the same route as currently used by all deep-draft vessels servicing the Passamaquoddy Bay port area. Deep-draft vessels bound for the ports of Bayside, New Brunswick, or Eastport, Maine, either enter the area via the Gulf of Maine and into Grand Manan Channel, or by transiting Grand Manan Basin into the Bay of Fundy. Downeast has proposed two transit routes. LNG vessels bound for Passamaquoddy Bay can either (1) enter the Gulf of Maine and transit up the Grand Manan Channel on the westerly side of Grand Manan Island to Head Harbour Passage or (2) enter the Grand Manan Basin and transit up the Bay of Fundy VTS on the easterly side of Grand Manan Island. According to the WSR, either route is acceptable to the Coast Guard. Both routes converge offshore in the general vicinity of the entrance to Head Harbour Passage, north-northeast of Campobello Island. A typical transit, from the time the LNG vessel enters Head Harbour Passage to the time it reaches the proposed Downeast LNG terminal, would take approximately two and one-half to three and one-half hours.

Downeast estimates that there would be one vessel every five to seven days in the winter (slightly more often than once per week), and one vessel every eight to ten days in the summer (or about every week and a half), approximately 60 vessels per year. The WSR recommends that three to four tractor tugs accompany each LNG vessel in the waterway and that Coast Guard authorized assets, as determined by the COTP, escort the LNG vessel to the terminal. In locations where the waterway is narrow, some mariners attempting to travel in the opposite direction of an LNG vessel traveling at 10 knots may need to wait up to 18 minutes for the LNG vessel to pass before proceeding on its way. The delay would increase up to 36 minutes when the LNG vessel is traveling at 5 knots and up to 60 minutes when the LNG vessel is traveling at 3 knots. For mariners near or upstream of the facility, an additional 60-minute delay may be experienced while the LNG vessel is berthed or turned. Other vessels may be allowed to transit through the LNG vessel security zones with the specific permission of the COTP determined on a case-by-case basis. Mariners and other users of the waterway would receive advance warning of an LNG vessel transit and associated waterway restrictions through various established communication methods and public service announcements.

A discussion of marine traffic and transportation as they relate to marine safety is included in section 4.12 of this EIS. The socioeconomic and environmental justice impacts associated with marine traffic are discussed in section 4.8 of this EIS. Large commercial vessels such as LNG vessels must coordinate closely with the Coast Guard and other waterway and port authorities in the area. This coordination and advance notice of the arrival and departure of LNG vessels, along with the implementation of vessel traffic management practices, as recommended by the Coast Guard's WSR, would ensure that other marine traffic, both commercial and recreational, would experience insignificant impacts as a result of the LNG vessel movements.

## 4.10 CULTURAL RESOURCES

Section 106 of the NHPA, as amended, requires the FERC to take into account the effect of its undertakings (including authorizations under Sections 3 and 7 of the NGA) on historic properties, and afford the ACHP an opportunity to comment. Downeast, as a non-federal party, is assisting the FERC in meeting its obligations under Section 106, providing data, analyses, and recommendations in accordance with the ACHP's implementing regulations at 36 CFR 800.2(a)(3). While we have delegated the gathering of cultural resources information to the applicant, the Commission retains its authority to make findings and determinations.

The COE, NOAA Fisheries, EPA, and the Coast Guard also have responsibilities for considering the impacts of their undertakings on historic properties under the NHPA. However, as the lead federal agency for this project, the FERC will jointly address compliance with the NHPA for all the federal cooperating agencies in this EIS. The sections below summarize consultations and cultural resources information, identify historic properties that may be affected by the project, update the status of compliance with the NHPA, and present our findings and recommendations.

### 4.10.1 Consultations

Interested and consulting parties concerned about the potential effects the project may have on historic properties have had multiple opportunities to comment through the public scoping period (discussed in section 1.4), during direct consultations with the applicant, and in response to our release of draft environmental documents. The FERC issued a Draft EIS in May 2009 and a Supplemental Draft EIS in March 2013. These documents were sent to a wide range of stakeholders on our environmental mailing list that included U.S. government agencies, such as the Department of the Interior (USDOI), the Maine State Historic Preservation Office (SHPO), interested Indian tribes and Native Americans, regional environmental groups, and non-governmental organizations. Their responses and comments on cultural resources issues are noted below.

#### 4.10.1.1 Consultations with the State Historic Preservation Office

Downeast initiated consultation with the Maine Historic Preservation Commission (the SHPO) on February 21, 2006. In a letter dated March 14, 2006, the SHPO requested that Downeast conduct terrestrial surveys to identify architectural and historic and prehistoric archaeological resources onshore and an underwater survey to identify offshore cultural resources. The SHPO indicated that there was one previously recorded prehistoric site (number 97.6) located near the proposed LNG terminal. Through subsequent telephone calls (June 7 and June 15, 2006) and correspondence, Downeast and the SHPO discussed survey methods.

On June 15, 2006, Downeast provided the SHPO with a project sensitivity assessment and proposal for Phase I survey. Four areas were identified as possessing high sensitivity for potential to contain precontact archaeological resources, and nine areas were identified as having moderate potential. Subsurface testing was recommended for those areas. The SHPO accepted this survey proposal in a letter to Downeast's contractor dated June 16, 2006.

Downeast provided the SHPO with draft copies of its *Phase I Historic Archaeological and Historic Architectural Survey Report* and *Phase IA and Phase IB Precontact Archaeological Survey Report* on August 8, 2006. Revised copies of those reports were submitted to the SHPO on October 23, 2006. Also on October 23, 2006, Downeast provided the SHPO with a copy of its *Marine Archaeological Technical Report*. On October 2, 2006, Downeast provided the SHPO with a copy of its draft Unanticipated Discovery Plan. The plan, entitled *Procedures for Guiding the Discovery of Unanticipated Cultural Resources and Human Remains,* is discussed below in section 4.10.3. In a letter to the SHPO dated December 6, 2006, Downeast addressed questions about potential visual impacts on historic properties resulting from LNG marine traffic.

We discussed the project with the SHPO on November 7, 2006. The SHPO indicated satisfaction with the approach taken by Downeast's archaeological contractors (Spiess 2006).

In a letter dated January 25, 2007, to Downeast's cultural resources consultant, the SHPO commented on the prehistoric, historic archaeology, and architectural survey reports it received on January 4, 2007. In that letter, the SHPO requested additional information about architectural resources. In a letter dated March 5, 2007, the SHPO requested additional information on historic fish weirs in Mill Cove.

In response to the SHPO's comments, in May 2007, Downeast provided a revised historic architectural survey report, and a report on the Mill Cove fish weirs. The SHPO commented on the revised architectural report in a letter dated June 25, 2007, and commented on the fish weir report in a letter dated June 19, 2007.

In January 2008, Downeast advised the SHPO of the amended pipeline route and requested continued consultation on the project. The SHPO responded on January 31, 2008, requesting additional archaeological and architectural surveys covering the new pipeline route. In a letter to the FERC on June 16, 2009, the SHPO stated that it had reviewed our Draft EIS for this project, and concurred with the information and recommendations contained in section 4.10 Cultural Resources. In addition, the SHPO indicated that it was still waiting for Downeast to provide data previously requested. As noted in our Draft EIS, the results of all cultural resources inventories, including the amended pipeline route and associated facilities, have not yet been filed with the Commission (see section 4.10.4 of this EIS).

#### 4.10.1.2 Consultations with Other Federal Agencies

Downeast consulted with the FWS in 2006 regarding the portion of the proposed pipeline that would cross the Moosehorn NWR. However, in January 2008, Downeast amended the pipeline route so that it no longer crosses the Moosehorn NWR.

The USDOI National Park Service (NPS), which administers the Saint Croix Island International Historic Site, in cooperation with Parks Canada, provided comments to the FERC about the project in a letter dated April 14, 2006. The park, comprising about 22 acres, including an island in the St. Croix River and two mainland parcels in Calais, Maine, was established to commemorate the first attempt by France to establish a colony in North America. It was designated a national monument in 1949, and recognized as an international historic site in 1884. The Saint Croix Island International Historic Site is located about 5.5 miles northwest of the proposed LNG terminal. The NPS is concerned about potential project-related impacts on the site, including impacts on air quality and noise, visual impacts, impacts from LNG marine traffic, and safety. In a November 7, 2006 data request, we asked Downeast to evaluate any potential project impacts on the Saint Croix Island International Historic Site. Downeast conducted a photo simulation assessment exercise, filed on April 9, 2007, that showed that only a portion of the proposed LNG terminal pier would be visible from the Interpretive Center at the Saint Croix Island International Historic Site. Downeast's consultant contends that there should be no project-related adverse visual impacts, because the proposed facilities would be a minor element in the background landscape of the viewshed from the Saint Croix Island International Historic Site.

The U.S. Department of the Interior Bureau of Indian Affairs (BIA) motioned for intervener status on behalf of the Passamaquoddy Tribe in its letter of February 29, 2008 to the Commission. The BIA indicated it was interested in participating in the resolution of outstanding issues regarding the mitigation of impacts on aquatic and terrestrial species, and the protection of tribal religious and cultural resources. The BIA, through the July 2, 2009 letter to the FERC from the USDOI commenting on our Draft EIS, stated that it believes that the development of this project may have effects on the traditional cultural practices of the Passamoquoddy Tribe. The BIA would like the applicant to consult regarding potential impacts on tribal trust lands. Consultations with Indian tribes and other Native Americans are discussed in more detail below in section 4.10.1.3.

On July 2, 2009, the USDOI, on behalf of its NPS, BIA, and FWS, provided the FERC with its comments on our Draft EIS. The NPS raised concerns about the potential for lighting at the LNG terminal to affect the quality of the night sky at the Saint Croix Island International Historic Site. The USDOI requested that Downeast adjust its terminal lighting system to minimize those impacts. The FWS is concerned about potential impacts on the Moosehorn National Wildlife Refuge, including effects on air quality. The BIA claims that the applicant has not provided it with copies of cultural resources reports. The BIA is concerned about potential project effects on traditional cultural properties, historic sites, and fisheries of importance to the Passamoquoddy Tribe. The USDOI disagreed with the area of potential effect (APE) defined by Downeast's consultants for the terminal tract and pipeline route (see sections 4.10.2.2 and 4.10.2.3 below). It would like the APE expanded to the entire bay where the terminal would be located, the shoreline visible along the waterway, and the visible swatch of the entire pipeline. However, the SHPO accepted the APE as defined by Downeast's consultants when it accepted the survey reports, and the USDOI comments far exceed the definition of the APE given in the ACHP's regulations for implementing Section 106 of the NHPA.[24]

In a letter dated May 8, 2007, the Natural Resources and Planning Manager for the Roosevelt Campobello International Park commented that the Sandia Zones of Concern appear to overlap park lands (see section 4.12.5 of this EIS for discussion of Sandia Zones of Concern). In a data request issued July 24, 2007, we asked Downeast to clarify if any historic structures within the

[24] 36 CFR 880.16(d) defines the APE as "the geographic area…within which an undertaking may directly or indirectly cause alternations in the character or use of historic properties…" There are no historic properties currently identified that would be adversely affected within the viewshed for the LNG terminal and pipeline. Nor would LNG vessel traffic in the waterway alter the character or use of historic properties overlapped by the Zones of Concern, any more than current ship traffic in the sea lanes does. Lastly, 36 CFR 800.4(a)(1) states that the agency defines the APE in consultation with the SHPO, or THPO for tribal lands. The FERC staff and SHPO agree on the definition of the APE by Downeast's consultants.

Roosevelt Campobello International Park would be overlapped by the Zones of Concern. Downeast responded, on August 13, 2007, that no historic structures within the Roosevelt Campobello International Park would be overlapped by the Zones of Concern, which extend up to 2.2 miles from the waterway for LNG vessel marine transit. In a letter to the FERC dated January 19, 2009, the Superintendent of the Park stated that any LNG facility development on the St. Croix River or in Passamaquoddy or Cobscook Bays would be inappropriate, and the Park Commission opposes the granting of any permits to Downeast.

In a letter to the FERC on July 5, 2009, commenting on our Draft EIS, the Executive Secretary/Superintendent for the Roosevelt Campobello International Park Commission stated that it still had concerns about potential impacts on air quality, and safety issues related to LNG vessel marine traffic in the waterway, including effects on tourism and visitors, vistas, and core structures at the park, such as the Franklin D. Roosevelt Summer Home and Park Visitor Center. On April 10, 2013, the Executive Secretary/Superintendent for the Roosevelt Campobello International Park Commission commented to the FERC on our Supplemental Draft EIS. The Park Commission pointed out that it is an intervenor in this proceeding, remains opposed to the project, and reiterated its safety concerns.

The St. Croix International Waterway Commission commented in a letter dated March 14, 2008 to the FERC that construction or operation of the project could result in disturbance or loss of native species, assemblages, and habitats having high ecological or cultural significance. It also commented that the project could result in loss of archaeological and historical resources within the waterway corridor due to construction or operation.

#### 4.10.1.3 Consultations with Indian Tribes and other Native Americans

The FERC has consulted with federally recognized Indian tribes that may have historically occupied or used the project area, and may attach religious or cultural significance to sites that may be affected by the project. A copy of our NOI issued March 13, 2006 was sent to the Passamaquoddy Tribe. In an April 15, 2006 letter to the FERC, the Passamaquoddy Tribal Historic Preservation Officer (THPO) raised concerns about tribal access to a cultural site located south of the proposed LNG terminal. The THPO’s letter indicated that traditional activities such as water crossings occurred in the region, that the terminal area was used as a tribal hunting site, and that an eighteenth century trading post may have been situated on the north side of Mill Cove. The THPO requested that a survey be conducted covering the LNG terminal and its associated waterway for LNG marine traffic, and the THPO would like the opportunity to review archaeological work plans.

We sent a copy of our September 18, 2006 supplemental NOI to the Passamaquoddy Tribe. We also sent copies of our December 1, 2006 and February 13, 2008 supplemental NOIs to the Passamaquoddy Tribe, Penobscot Indian Nation, Aroostock Band of Micmacs, and Houlton Band of Malisset Indians. The Passamaquoddy Tribe filed as an intervener in this proceeding on January 11, 2007, because of its interests in potential project impacts on ecological, spiritual, and cultural resources.

The Passamaquoddy Tribe at Pleasant Point commented to the FERC in a February 20, 2008 letter about the amended pipeline route. The tribe objected to the placement of the pipeline across islands within the St. Croix River. They are concerned about potential project-related impacts on salmon and the river's ecosystem. On May 3, 2013, Edward Bassett, a member of the Pleasant Point Reservation Passamaguoddy Tribal Council filed comments with the FERC in response to our Supplemental Draft EIS. He also raised concerns about the proposed pipeline route crossing the St. Croix River, which may have effects on tribal fishing activities and impacts on reservation islands. Further, he suggested that Downeast continue to have face-to-face consultations with the tribe. Downeast proposes to use an HDD to cross under the St. Croix River, and in response to these comments has amended the pipeline route to avoid encroaching on any Indian lands, and disturbing sensitive environments during construction and operation of the sendout pipeline.

Besides federally recognized Indian tribes, some other Native American organizations have commented to the FERC about the Downeast LNG Project. St. Mary's First Nation Fisheries corresponded with the FERC in January 2007. They expressed concerns about possible impacts on their fishing and sustenance rights. They also expressed concerns about potential impacts on threatened or endangered whale species, such as the North Atlantic right whale, fin whale, humpback whale, and harbor porpoise. Whales are connected to First Nation creation stories and whale ceremonies are still practiced. This EIS addresses potential project-related impacts on marine mammals, including whales in section 4.5.2. Project-related impacts on fishing are addressed in sections 4.7 and 4.8. Other Native American groups have filed as interveners in Downeast's proceeding before the FERC. This includes the Union of New Brunswick Indians and the Nulankeyutmonen Nkihtahkomikumon (We Take Care of Our Land). In a letter dated January 15, 2007, the Union of New Brunswick Indians, which represents 12 First Nations in the Canadian Province of New Brunswick, raised concerns about the preservation of aboriginal treaty rights. The Nulankeyutmonen Nkihtahkomikumon, consisting of three individuals from the Passamaquoddy Tribe, in a letter dated January 19, 2007, raised concerns about possible impacts of LNG marine traffic on traditional waters and fisheries, and potential impacts on a traditional cultural site at Split Rock.

On July 6, 2009, the law firm of Shems Dunkiel Raubvogel & Saunders, representing the Nulankeyutomonen Nkihtahkomikumon, Save Passamaquoddy Bay-Canada, Inc., and Save Passamaquoddy Bay-U.S., Inc. (Three Nation Alliance or TNA) filed with the FERC comments on our Draft EIS. That letter mentioned several historic districts not addressed in the draft, which we have listed in this final EIS (see section 4.10.2.1).

The Coast Guard has also consulted directly with the Passamaquoddy Tribe and other Native Americans. The tribe was invited to participate in Coast Guard working groups related to the proposed Downeast project. Elements of the Pleasant Point Reservation tribal government, including law enforcement, fire, emergency response, and environmental management personnel, participated in the working group's evaluation of Downeast's WSA. A representative of the Coast Guard met with Edward Barrow, representing the Passamaquoddy Tribe, on December 13, 2006, and in response to tribal requests the Coast Guard has engaged in further outreach activities (Garrity 2006).

In a September 11, 2007 submittal to the Coast Guard and the Commission, the TNA provided comments to the Coast Guard's information requests. Citing provisions for aboriginal and sustenance licenses at 12 M.S.R.A §6302-A, TNA contends that Passamaquoddy tribal members maintain aboriginal fishing rights to the waters proposed for use by Downeast. Downeast disagrees, and stated that the Passamaquoddy Tribe does not have sovereignty or any other special fishing or sustenance rights over waters proposed for use by the project. Impacts on tribal fishing grounds would be similar to those described in sections 4.7.3.1 and 4.7.3.2 of this EIS with regard to public, recreation, and special land uses. However, as noted by the Coast Guard in their comments on the draft EIS, the Coast Guard ultimately has the jurisdictional authority to enforce safety and security measures within the navigable waters of the United States, and is sensitive to the fishing rights of the Passamaquoddy Tribe. The Coast Guard's WSR includes a recommendation that Downeast provide written verification of collaboration with and acceptance from the Passamaquoddy Nation, ensuring that its jurisdictional interests and public safety and security needs are adequately met. In addition to the FERC's consultations with Indian tribes, Downeast contacted Indian tribes in Maine about its proposed project, including the Houlton Band of Maliseet Indians, Aroostock Band of Micmacs, Penobscot Nation, and Passamaquoddy Tribe. On March 13, 2006, the Penobscot Nation commented that the project would have no impact on cultural resources of significance to them. However, the Penobscot Nation requested that the Passamaquoddy Tribe be contacted, and that the Penobscot Nation should be notified in the event that Native American cultural materials are encountered during the course of the project.

Downeast met with the Passamaquoddy THPO on June 21, 2006. The THPO requested that Downeast purchase a parcel of land on the south side of the proposed LNG terminal to provide tribal access to a cultural site. Downeast requested more specific data about the location of the eighteenth century trading post. The THPO indicated that areas along the pipeline route should be surveyed and tested that are sensitive for cultural resources, including water crossings and potential caribou hunting camps. The THPO requested that Downeast consider involving the tribe in the project, providing assistance for tribal cultural education programs, and that it make a presentation about the project to the joint Tribal Council.

On August 10, 2006, Downeast provided copies of its draft terrestrial cultural resources survey reports to the Passamaquoddy Tribe, Aroostook Band of Micmac Indians, and Houlton Band of Maliseet Indians, and revised copies of these reports were sent to the tribes on October 23, 2006. Downeast also provided the tribes with copies of its Phase I Marine Archaeological Survey Report. In addition, on September 28, 2006, Downeast submitted copies of its draft Unanticipated Discovery Plan to the Passamaquoddy Tribe, Aroostook Band of Micmac Indians, and Houlton Band of Maliseet Indians.

On September 16, 2006, the Passamaquoddy THPO sent a letter to Downeast reiterating its concerns. These concerns include the location of the proposed LNG terminal in direct line of travel to a cultural site of significance to the tribe; location of the proposed LNG terminal near an old village site and historic trading post; proposed pipeline crossing of waterbodies that may be traditional fishing sites, and sites for tribal travel, camping, and quarrying activities; and the proposed pipeline crossing of Moosehorn NWR, which was historically used by the tribe for hunting caribou. In an April 9, 2007 response to our March 19, 2007 data request, Downeast indicated that the company is continuing to consult with the Passamaquoddy Tribe. Downeast held a meeting with the Passamaquoddy THPO and an environmental advisor to the tribe on May 3, 2007. The THPO informed Downeast that the Passamaquoddy Tribal Council had entered into a development agreement with Quoddy Bay LNG[25] that prohibited the Passamaquoddy Tribe from formally consulting with Downeast. The THPO agreed to continue to hold informal discussions with Downeast about cultural resources issues.

In an April 6, 2007 communication to Downeast, filed on June 5, 2007, the THPO stated that the potential impact of the proposed LNG pier on access to a traditional cultural sacred site had been discussed at a previous meeting. Downeast indicated to the THPO that the company was looking for another point of access for the tribe.

In a May 4, 2007 submittal to the Maine BEP, a copy of which was filed by Downeast on June 5, 2007 in its proceeding before the FERC, Bear Creek Investments (BCI) stated that it has executed a purchase agreement for the property that abuts the proposed Downeast LNG terminal tract on the southeast. According to an article published in the *Bangor Daily News* on May 8, 2007, a copy of which was filed with the FERC by Downeast on June 5, 2007, BCI plans to build the Wabanaki Interpretive and Conference Center on this property. The center would be developed in consultation with the Passamaquoddy Tribe, and is designed, among other things, to provide access to sites that the tribe considers historically and culturally important, including Pulpit Rock. According to the architectural firm that designed the Center, there are no immediate plans to commence construction of the project. We have no additional information on the status of this project.

### 4.10.2 Cultural Resources Overviews and Inventories

#### 4.10.2.1 Waterway for LNG Marine Traffic

Stakeholders have raised concerns about potential project-related impacts from LNG marine traffic on historic resources at Campobello Island, New Brunswick, Canada, including the 1829 Head Harbour Light station and the former summer home of United States President Franklin Roosevelt within the Roosevelt Campobello International Park. Downeast indicated that LNG marine traffic would not pass within 1,500 feet of Campobello Island. There are five historic summer cottages within the park, on the north side of the island near the junction of Route 774 and Glensevern Road. The closest of these historic cottages to the LNG vessel transit route would be approximately 2.6 miles. Downeast's architectural consultant did a site file search within 2.1 miles of the LNG marine traffic route, and identified 10 properties listed on the NRHP in the towns of Robbinston and Eastport (PAL 2006). Downeast, in an April 30, 2007 filing, clarified that three NRHP-listed properties, all historic residences, are located in Robbinston, about 2.5 miles north of the proposed LNG terminal. There are four individual NRHP-listed historic sites (a church, a house, a former high school, and an eighteenth century fortification barracks) and two Historic Districts located in Eastport, about 14 miles south of the proposed LNG terminal. Lastly, the West Quoddy Head Lighthouse, in Lubec, Maine, located between 1.0 and 2.1 miles from the LNG vessel marine transit route, is listed on the NRHP. The TNA mentioned that the town of Eastport, on Moose Island, along the LNG vessel marine transit

[25] On October 17, 2008, FERC dismissed Quoddy Bay LNG's application to build and operate an LNG import terminal and associated pipeline. This dismissal is without prejudice to Quoddy Bay filing a new application in the future.

route, contains the Boynton Street Historic District (consisting of three buildings), Fort Sullivan (consisting of a barracks and remains of a powder magazine), and the Eastport Historic District (consisting of 29 buildings), which are all listed on the NRHP.

The Passamaquoddy Tribe's Pleasant Point Indian Reservation is within about 1.0 mile of the LNG vessel transit route. The Passamaquoddy Tribe and Downeast disagree about aboriginal fishing rights to the waters proposed for use by LNG marine traffic to and from the terminal. The Coast Guard ultimately has jurisdictional authority to enforce safety and security measures within the navigable waters of the United States, and is sensitive to the fishing rights of the Passamaquoddy Tribe.

In a November 20, 2006 data request, we asked Downeast to consult with the SHPO regarding potential impacts on cultural resources resulting from LNG marine traffic. The SHPO responded to that request, in a January 25, 2007 letter to Downeast's cultural resources consultant, that LNG vessel transit, in and of itself, is not likely to affect aboveground or archaeological resources, and no further work is necessary along the waterway for LNG marine traffic. We concur with the SHPO. Given the design of LNG vessels, the safety and security measures adopted by Downeast in its WSA, and the mitigation measures recommended in the Coast Guard WSR, it is highly unlikely that an accident or spill from an LNG vessel transiting within the waterway would have adverse effects on any historic properties.

#### 4.10.2.2 LNG Terminal

Downeast's application included copies of reports for its marine archaeological survey, prehistoric archaeological survey, historic archaeological survey, and architectural survey. Downeast's archaeological consultants defined the APE for the terrestrial portion of the proposed LNG terminal to be 47 acres, including areas for the LNG storage tanks, vaporizers, administrative buildings, access roads, and parking lots. In its application, Downeast proposed to leave the remaining 33 acres of its 80-acre parcel as an undeveloped buffer.

Background research indicated that a previously documented prehistoric shell midden (site number 97.6) was reported near the north shore of Mill Cove. However, Downeast claims that this site is not within the APE for the LNG terminal.

In April 2006, Downeast's prehistoric archaeological contractor conducted a walkover survey of the terrestrial portion of the LNG terminal APE. No evidence of Native American occupations was found during this survey of upland areas (Clark et al. 2006).

As noted by interested stakeholders, Mill Cove, in the area of Downeast's terminal marine facilities, has the potential to contain prehistoric fish weirs. Downeast conducted a marine archaeological survey and filed a draft copy of the report of the investigations with the FERC on November 7, 2006. The study encompassed the proposed pier and berthing facilities, covering an area of about 57 acres offshore. The marine field reconnaissance consisted of geophysical remote sensing using a multi-beam echo sounder, side-scan sonar, sub-bottom profiler, marine magnetometer, and single-beam bathymetry system, in association with geotechnical borings. The marine survey found no evidence of submerged cultural resources, including prehistoric archaeological sites or fish weirs, or historic shipwrecks (Robinson and Brett 2006).

Two offshore historic-era fish weirs were documented in the historical archaeological survey report for the proposed LNG terminal. A local informant, Gerald Morrison, told Downeast that his family operated one weir south of the LNG terminal for catching herring during the 1950s. In 1976, Mr. Morrison built a new weir just east of the proposed location for the LNG terminal pier. This modern weir is still in use (Booth et al. 2006).

After local residents expressed concerns that other historic fish weirs may exist in Mill Cove, the SHPO staff conducted a site visit that found unrecorded resources, and requested that Downeast conduct additional investigations. In May 2007, Downeast's contractor reported an evaluation of two previously unrecorded fish weirs (site numbers ME 371-009 and ME 371-010). The report concluded that the two sites are remains of late nineteenth or early twentieth century fish weirs most likely constructed to catch either smelt or herring. The contractor concluded that the weirs are highly deteriorated and do not meet the criteria for eligibility to the NRHP (Booth and Wheeler 2007).

Historic research identified a building labeled as the "McCleland" residence on an 1881 map in the vicinity of the proposed LNG terminal. In April 2006, Downeast's historic archaeological contractor recorded a cellarhole and barn associated with the McCleland farmstead as site number ME-371-005. The contractor indicated that the site is located north of the LNG terminal parcel boundaries, outside of the APE, and therefore no additional testing or research was conducted (Booth et al. 2006).

Downeast filed a revised historic architectural survey report on May 30, 2007. No architectural sites were identified within the LNG terminal tract, but there were six standing historic structural complexes noted within the viewshed for the terminal. In its June 25, 2007 review of the revised architectural survey report, the SHPO did not identify any of the historic complexes within the viewshed of the proposed LNG terminal as being eligible for the NRHP. However, additional data was requested by the SHPO for the farmstead at 235 Ridge Road in Robbinston before an assessment of its NRHP eligibility can be made. According to an August 13, 2007 filing by Downeast, in response to our July 24, 2007 data request, this house faces north, away from the LNG terminal, located about 0.5 mile to the southeast of it. The house is surrounded by trees, and we believe that the LNG terminal would have no adverse visual impacts on this site.

The SHPO reviewed Downeast's marine survey report in a letter dated November 14, 2006, and found it acceptable. The SHPO accepted Downeast's historic archaeology survey report in a letter dated January 25, 2007. In a letter dated June 19, 2007, the SHPO accepted the report evaluating the historic fish weirs, and concurred that they are not eligible for the NRHP. We agree with the SHPO that no historic properties were identified that would be affected within the APE for the LNG terminal.

#### 4.10.2.3 Sendout Pipeline

A stakeholder requested an analysis of potential project-related impacts on archaeological resources in the Meddybemps Lake area. Since the proposed pipeline route avoids the Meddybemps Lake area, we believe that the project would have no impacts on archaeological resources in that area, and no further analyses are necessary.

An archaeological site file search indicated that a previously recorded prehistoric site (number 96.08) and historic homestead site (number ME-024-001) were located in the vicinity of Stony

Brook, where the proposed pipeline would parallel the EMEC powerline. Downeast's prehistoric archaeological consultant conducted field survey and testing in this area, and determined that site numbers 96.08 and ME-024-001 are located on the north side of the powerline, while the proposed Downeast sendout pipeline would be routed on the south side of the powerline. As currently designed, the project should avoid impacting these sites since they are outside of the proposed pipeline construction right-of-way, so no further work was done (Clark and Cole-Will 2006; Booth et al. 2006).

Downeast's archaeological consultants defined the APE for the pipeline as a survey corridor 200 feet wide (100 feet on each side of the proposed centerline), except where the pipeline would be adjacent to roads, where the survey corridor was 100 feet from the road shoulder. Based on its research design, Downeast's prehistoric archaeological contractor conducted a pedestrian inventory of a total of 21.3 miles of selected portions of the pipeline route (between MPs 0.0 to 11.0, 12.9 to 13.1, 13.4 to 17.9, 18.1 to 20.1, 22.0 to 23.0, and 24.7 to 27.1). Twelve locations were subjected to subsurface archaeological testing (at MPs 1.0, 7.6, 7.9, 8.6, 8.7, 14.2, 14.4, 14.8, 17.5, 19.2, 22.1, and 25.9). We note that, based on the amended sendout pipeline route, the areas along the original route between MP 10.2 and MP 17.7, including three testing locations, are no longer within the APE for the pipeline.

The testing resulted in the discovery of one new buried prehistoric archaeological site (number 96.09) in the vicinity of Conic Stream (Clark et al. 2006). This area would be avoided by the amended pipeline route, so no additional work is required at this site.

Downeast's historical archaeological consultant reviewed historic maps and conducted on-the-ground inspections of a total of about 11.5 miles where potential historic sites might be located. The historical research identified two historic homesteads, a schoolhouse, a cemetery, and a quarry that may be located near the original pipeline route, but were not confirmed by on-the-ground inspections (Booth et al. 2006). The surveys resulted in the recording of seven newly identified historic archaeological sites (numbers ME-371-003, 004, 006, 007, 008, 011, and 012). These sites include the remains of five farmsteads, a quarry, and a dam.

Three of the historic farmstead sites (numbers ME-371-003, 004, and 006) were archaeologically tested in June and October 2006. Testing at site ME-371-003 (J. Tramble Homestead) indicated that the site boundary is about 144 feet west of the proposed pipeline centerline, and therefore this site should not be affected by project construction. Site ME-371-004 (W. Trimble Homestead) is located about 230 feet west of centerline. However, it may be affected if Downeast uses McNeil Road for access. As a result of testing at site ME-371-006 (McNeil/Nash Homestead), the site was evaluated as not containing significant remains and is probably not eligible for the NRHP. A modern camper is currently parked within the site boundaries.

A nineteenth century schoolhouse was noted on historic maps on the west side of McNeil Road in this vicinity, but was not found during on-the-ground inspections. Also in the vicinity of the McNeil/Nash Homestead was a historic rock wall that was not recorded as a historic archaeological site. Nevertheless, Downeast's historic archaeological contractor recommended that the rock wall should be rebuilt if it is disturbed by pipeline construction activities. In an August 13, 2007 filing, Downeast submitted a plan, dated July 2007, outlining procedures it would implement to ensure that historic rock walls affected during pipeline construction activities would be properly identified, recorded, and restored after construction.

No further work was done at the other newly recorded historic archaeological sites, because they appear to be outside of the proposed pipeline construction right-of-way and should not be affected by the project. For example, site ME-371-007 (Schoolhouse Road Cellarhole) is about 895 feet east of the proposed centerline, and site ME-371-008 (J. Larner Homestead) is about 220 feet east.

Downeast conducted an architectural survey to identify historic standing structures that may be within the viewshed of the project (PAL 2006). In a letter dated January 25, 2007, the SHPO commented that the architectural survey report did not meet its standards and requested additional information regarding aboveground resources potentially affected by the pipeline.

Downeast provided a revised architectural survey report dated May 2007. That report identified 36 historic complexes with standing structures within the APE for the pipeline. Five of those historic complexes were evaluated as eligible for the NRHP (Porterfied and Olausen 2007).

The SHPO's review of the revised architectural survey report, dated June 25, 2007, indicated that it disagreed with Downeast's consultant, and that all but one of the identified historic structural complexes do not qualify for the NRHP. The SHPO requested additional information for one site before it would make a final finding of eligibility, and also requested corrections to the report maps before it would assess project impacts. In a letter dated January 25, 2007, the SHPO accepted the historical archaeological report submitted by Downeast's consultant, and agreed with its recommendations relative to the proposed sendout pipeline. The SHPO also found the prehistoric archaeological survey report done for Downeast to be acceptable. However, it noted that two areas identified as being sensitive for prehistoric archaeological sites where access was previously denied still require survey and testing in the future (at MP 1.0 and MP 6.7). In addition, survey information for the amended portion of the pipeline route (MP 11.6 to MP 17.7) has not been filed with the Commission. We will defer making determinations of eligibility and effect until the entire APE for the pipeline is inventoried, and the SHPO has had the opportunity to comment on all reports, including a revised architectural survey report that addresses its previous concerns.

### 4.10.3 Unanticipated Discoveries

In our August 24, 2006 data request to Downeast, we asked for a project-specific plan to handle the unanticipated discovery of cultural resources or human remains during project construction and operation. A draft plan, entitled *Procedures for Guiding the Discovery of Unanticipated Cultural Resources and Human Remains*, was filed with the FERC on October 2, 2006, and also provided to the SHPO and interested Indian tribes. The SHPO reviewed the plan, and in a letter dated October 11, 2006, requested revisions. A revised plan was filed with Downeast's application. The SHPO and the tribes have not yet commented on the revised plan. Pending SHPO approval and acceptance by the tribes consulted, we believe that the plan is acceptable.

### 4.10.4 Compliance with the NHPA

The FERC consulted with Indian tribes to identify sites of religious and cultural importance that may be affected by the project. Downeast has assisted us in addressing our responsibilities under Section 101(d)(6) of the NHPA, and 36 CFR 800.2(c)(2) by contacting Indian tribes in Maine about the project. The Passamaquoddy Tribe and other Native Americans have indicated concerns about potential project impacts on traditional cultural properties, including restricting access to sites located in Mill Cove. Downeast has not documented that it has resolved issues related to potential project impacts on traditional cultural properties raised by the Passamaquoddy Tribe and other Native Americans. Therefore, in order to ensure that the project would have no adverse impacts on properties of traditional religious and cultural importance to an Indian tribe, **we recommend that:**

- **Prior to construction, Downeast should file with the Secretary documentation of continued consultations with the Passamaquoddy Tribe,** BIA, **and other appropriate Indian tribes and Native Americans interested in the project's potential impacts on cultural resources, including access to sites in Mill Cove, and seek resolution of identified project-related impacts on archaeological sites, burials, existing historic properties, and sites of religious or cultural importance within the APE.**

We have not yet completed the process of complying with Section 106 of the NHPA. There are portions of the pipeline route that still require archaeological survey and testing. In addition, the architectural survey report should be revised to address issues raised by the SHPO.

Once data are complete, the FERC, in consultations with the other federal cooperating agencies and the SHPO, will make determinations of NRHP eligibility and project impacts. If any historic properties would be adversely affected by the project, we would seek ways to resolve those impacts, develop a Memorandum of Agreement if appropriate, and provide the ACHP with an opportunity to comment. The FERC will complete the Section 106 process before notifying Downeast that construction may proceed.

To ensure that the Commission's responsibilities under the NHPA are met, **we recommend that:**

- **Downeast should not begin construction of facilities and/or use of all staging, storage, or temporary work areas and new or to-be-improved access roads until:**

  **a. Downeast files with the Secretary:**
  **(1) remaining cultural resources survey report(s);**
  **(2) site evaluation report(s) and avoidance or treatment plan(s), as required; and**
  **(3) comments on the cultural resources reports and plans from the Maine SHPO, and interested Native Americans and Indian tribes.**

  **b. the ACHP is afforded an opportunity to comment if historic properties would be adversely affected; and**

  **c. the FERC staff reviews and the Director of OEP approves the cultural resources reports and plans, and notifies Downeast in writing that treatment measures (including archaeological data recovery) may be implemented and/or construction may proceed.**

  **All materials filed with the Commission containing location, character, and ownership information about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "CONTAINS PRIVILEGED INFORMATION – DO NOT RELEASE."**

## 4.11 AIR QUALITY AND NOISE

### 4.11.1 Air Quality

Construction and operation of the project can potentially have an effect on local and regional air quality. We have identified the best estimate of exhaust emissions and emissions from fugitive dust from all construction operations as well as the direct and indirect emissions from the facilities. Although air emissions would be generated by construction activities involving the proposed pipeline and LNG terminal, the majority of air emissions associated with the project would result from the operation of the LNG terminal and the indirect emissions from the LNG vessels. We have attempted to quantify the impact of these emissions from the project, along with neighboring facilities on local and regional air quality.

#### 4.11.1.1 Regional Climate

The proposed LNG terminal and sendout pipeline are located in Washington County along the northeast coast of Maine. This region is strongly influenced by the ocean temperature and coastal weather patterns. Other climate influences include regional and subregional weather patterns and land topography.

Historical climate data for the nearby City of Eastport, Maine demonstrates the daily and seasonal climate variability for the project area. Average daily high temperatures range from 30.1°F (-1.1ºC) in January to 74.5°F (23.6ºC) in July and August. Daily minimum temperatures range from 13.7°F (-10.2ºC) in January to 54.5°F (12.5ºC) in August. The annual average temperature is 44.1°F (6.7ºC). Extreme temperatures in Eastport for the entire period of record (1926 to 2005) range from a low of -23°F (-30.6ºC) to a high of 98°F (36.7ºC). Sea breezes in coastal areas help to reduce the frequency of high temperatures that occur more often in inland areas.

Winds blow predominantly from the west and northwest in the cold months and from the south and southwest in the warm months, with average speeds of 9.3 mph in the winter to 12.4 mph in the summer. Stronger winds blow primarily from the west. During winter, significant storms may occur with high winds and heavy rain or snow.

The waters in the Bay of Fundy are among the foggiest areas in the world. Seasons that produce the greatest contrast in temperature between sea surface and the air produce the densest fog. For this reason, fog is generally more prevalent in summer than winter; however, fog can develop any day of the year. Fog occurs an average of 112 days per year in Eastport, and heavy fog with visibility less than a quarter mile occurs 35 to 40 days per year.

#### 4.11.1.2 Existing Air Quality

The term *air quality* refers to relative concentrations of pollutants in the ambient air. The subsections below describe well-established air quality concepts that are applied to characterize air quality and to determine the significance of increases in air pollution.

Federal and state ambient air quality standards (AAQS) have been designed to protect human health and the environment from airborne pollutants. AAQS establish limits on the concentration of pollutants in the ambient air. The EPA has developed National Ambient Air Quality Standards (NAAQS) for criteria air pollutants such as nitrogen oxides ($NO_x$) and carbon monoxide (CO), ozone ($O_3$), sulfur dioxide ($SO_2$), and inhalable particulate matter ($PM_{2.5}$ and $PM_{10}$). $PM_{2.5}$ includes particles with an aerodynamic diameter less than or equal to 2.5 microns, and $PM_{10}$ includes particles with an aerodynamic diameter less than or equal to 10 microns. VOCs are the precursor pollutant for ozone generation.

Individual states may adopt standards more stringent than the NAAQS. AAQS promulgated by the Maine DEP are published in Chapter 110 of the Maine DEP regulations. In some cases, the Maine AAQS are more stringent than the NAAQS. In addition, the Maine DEP has also established ambient air quality standards for pollutants not addressed by the NAAQS.

Primary NAAQS levels are targeted for protection of human populations, in particular, sensitive populations such as asthmatics, children, and the elderly. Secondary NAAQS are targeted for protection of public welfare (visibility; damage to animals, crops, vegetation, and buildings). The National and Maine AAQS are presented in table 4.11.1.2-1.

TABLE 4.11.1.2-1

**National and State Ambient Air Quality Standards**

| Air Pollutant | Averaging Period | NAAQS ($\mu g/m^3$) | Maine AAQS ($\mu g/m^3$) |
|---|---|---|---|
| Carbon Monoxide | 1 hour | 40,000 | 40,000 |
| | 8 hour | 10,000 | 10,000 |
| Lead | 24 hour | NA | 1.5 |
| | Quarter | 1.5 | NA |
| | Rolling 3-Month Average | 0.15 | NA |
| Nitrogen Dioxide | 1 hour | 189 | NA |
| | Annual | 100 | 100 |
| Particulate Matter less than 10 microns | 24 hour | 150 | 150 |
| | Annual | NA | 40 |
| Particulate Matter less than 2.5 microns | 24 hour | 35 | NA |
| | Annual | 15 | NA |
| Sulfur Dioxide | 1 hour | 195 | NA |
| | 3 hour | 1,300 | 1,150 |
| | 24 hour | 365 | 230 |
| | Annual | 80 | 57 |
| Ozone | 8 hour | 147 | NA |
| Hydrocarbons | 3 hour | NA | 160 |
| Photochemical Oxidants | 1 hour | NA | 160 |
| Total Chromium a/ | 24 hour | NA | 0.3 |
| | Annual | NA | 0.05 |
| Hexavalent Chromium | 24 hour | NA | MDL or 0.001 |

a/ The total chromium standards apply until an analytic procedure to measure hexavalent chromium in the ambient air is approved. At that time, the total chromium standard would be replaced by the 24 hour hexavalent chromium standard.
MDL = method detection limit
NA = not available or not applicable
$\mu g/m^3$ = micrograms per cubic meter

A geographic area that satisfies the NAAQS for a given pollutant is considered an attainment area with respect to that pollutant. Likewise, an area that does not satisfy the NAAQS for a pollutant is considered a nonattainment area with respect to that pollutant. Thus, an area may be in attainment with respect to some pollutants and nonattainment for others. Regional air monitors provide the basis to determine whether an area is or is not in attainment. In the absence of air monitor data, an area may be designated as "unclassifiable" with respect to one or more pollutants. NAAQS attainment status designations for Maine, Massachusetts, and New Hampshire are shown in 40 CFR 81, Subparts 320, 322, and 330, respectively.

The proposed project would be located near the border with the Canadian province of New Brunswick. Projects in New Brunswick are subject to both Canadian and New Brunswick Ambient Air Quality Objectives as shown in table 4.11.1.2-2.

TABLE 4.11.1.2-2

**Canadian and New Brunswick National Ambient Air Quality Objectives (and Acceptable Levels)**

| Air Pollutant | Averaging Period | New Brunswick Maximum Permissible Ground Level Concentration in Saint John County ($\mu g/m^3$) | Canadian National Ambient Air Quality Objectives Maximum Desirable Level / Acceptable Levels ($\mu g/m^3$) |
|---|---|---|---|
| Sulfur Dioxide | 1-hour | 450 | 450 / 900 |
| | 24-hour | 150 | 150 / 300 |
| | Annual | 30 | 30 / 50 |
| Nitrogen Oxides | 1-hour | 400 | -- / 400 |
| | 24-hour | 200 | -- / -- |
| | Annual | 100 | 60 / 100 |
| Carbon Monoxide | 1-hour | 35,000 | 15,000 / 35,000 |
| | 8-hour | 15,000 | 6,000 / 15,000 |
| Total Suspended Particulates | 24-hour | 120 | -- / 120 |
| | Annual | 70 | 60 / 70 |
| Respirable Particulate Matter ($PM_{2.5}$) | 24-hour | -- | 30 / -- |
| Ozone | 1-hour | -- | 100 / 160 |
| | 24-hour | -- | 30 / 50 |
| | Annual | -- | -- / 30 |

Greenhouse gases (GHG), the most common of which are carbon dioxide ($CO_2$), methane ($CH_4$), nitrous oxide ($N_2O$), $O_3$, hydrofluorocarbons, and perfluorocarbons, are naturally occurring pollutants in the atmosphere and products of human activities, including burning fossil fuels. In 2009, EPA determined that current and projected concentrations of the key GHGs in the atmosphere threaten public health and welfare due to climate change effects. Fossil fuel combustion emits $CO_2$, $CH_4$, and $N_2O$. GHG emissions are generally calculated in terms of carbon dioxide equivalents ($CO_{2e}$) where the heating potential of each gas is expressed as a multiple of the heating potential of $CO_{2e}$.

**Air Quality Control Regions**

An Air Quality Control Region (AQCR) is a geographic area (generally urbanized areas or consolidated metropolitan areas), which, due to existing air quality or projected growth rates, has the potential to exceed the NAAQS. The CAA requires each state to adopt and submit a State Implementation Plan (SIP) to implement, maintain, and enforce the NAAQS for each nonattainment AQCR. The SIP identifies source control strategies to achieve and maintain NAAQS, or identifies the methods (e.g., air sample collection, report submittals) by which nonattainment areas can demonstrate progress toward attainment. Upon approval by EPA, the rules in the SIP become federally enforceable. The SIP for Maine is published in 40 CFR Part 52 Subpart U.

The EPA assigns a number and a name to each ACQR. The LNG project would be located in ACQR-109, the Down East Intrastate AQCR. The proposed area for the LNG terminal and sendout pipeline is designated as attainment or unclassified for all NAAQS. The nearest nonattainment area to the proposed Downeast LNG terminal location is in Eastern Hancock County about 56 miles to the southwest.

The attainment status designations for Maine are listed at 40 CFR 81.320. The areas previously designated as nonattainment for ozone were, on December 11, 2006, reclassified as maintenance areas for ozone. The entire state of Maine is located within the Ozone Transport Region (OTR). The CAA sets out specific requirements for Maine and other northeast states that make up the OTR.

**Air Quality Monitoring**

To evaluate the impact of a project on air quality, the existing air quality must first be known. To achieve this, the state of Maine operates a criteria pollutant air monitoring network that collects ambient concentration data to estimate air quality for most locations within the state. This data is made available to the public via the EPA AirData database.

For the LNG terminal area and sendout pipeline, existing background concentrations of criteria pollutants were determined based on the available monitored data that was judged to be most representative based on distance from the project site, proximity to the coast, and the general land use nearby. Table 4.11.1.2-3 summarizes the existing ambient air pollutant concentrations determined from air monitor data over a recent five-year time span. As the table shows, the existing air quality levels in the vicinity of the LNG terminal and sendout pipeline are below the Maine AAQS. As stated previously, the region is in attainment for all federal NAAQS. Federal and state programs and regulations (discussed below) are established with the goal of ensuring that emissions from proposed projects do not cause significant deterioration of the existing air quality.

| TABLE 4.11.1.2-3<br>**Existing Ambient Air Quality Monitoring Data Representative for the Project Area** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Pollutant** | **Monitor** | **Avg. Time** | **Units** | **Measured Concentrations a/** | | | | | |
| | | | | **2003** | **2004** | **2005** | **2006** | **2007** | **AAQS b/** |
| $NO_2$ | Bar Harbor | Annual | ppm | - | 0.001 | 0.001 | 0.001 | 0.001 | 0.053 |
| CO | Bar Harbor | 1-Hour | ppm | 0.6 | 0.3 | 0.6 | 0.3 | 0.3 | 35 |
| | | 8-Hour | ppm | 0.4 | 0.3 | 0.4 | 0.3 | 0.3 | 9 |
| $SO_2$ | Bar Harbor | 3-Hour | ppm | - | 0.007 | 0.008 | 0.005 | 0.006 | 0.50 |
| | | 24-Hour | ppm | - | 0.004 | 0.006 | 0.003 | 0.004 | 0.14 |
| | | Annual | ppm | - | 0.003 | 0.002 | 0.001 | 0.001 | 0.03 |
| **$PM_{10}$** | **Bangor** | **24-Hour** | **µg/m$^3$** | **48** | **44** | **48** | **42** | **53** | **150** |
| | | Annual | µg/m$^3$ | 22 | 18 | 20 | 19 | 19 | 40 |
| $PM_{2.5}$ | Bar Harbor | 24-Hour | µg/m$^3$ | 22 | 19 | 19 | 20 | 22 | 35 |
| | | Annual | µg/m$^3$ | 6.7 | 5.9 | 5.9 | 5.1 | 5.4 | 15 |
| $O_3$ | Perry | 8-Hour | ppm | - | 0.055 | 0.06 | 0.057 | 0.056 | 0.075 |

a/ Except for ozone, annual measurements represent the maximum measured pollutant level, and short-term measurements represent the second highest pollutant level. For ozone, the table shows the fourth highest measured levels.
b/ The most stringent AAQS is presented here. AAQS values for CO, $NO_2$, and $SO_2$ are converted from µg/m$^3$ to ppm.

### 4.11.1.3 Regulatory Requirements for Air Quality

Federal and state regulations are established to protect existing air quality from new air pollution sources. Federal regulations are established in response to the CAA. State regulations must meet or exceed federal regulations. Upon approval by the EPA administrator, CAA permit responsibilities, compliance monitoring and enforcement are delegated to the state. The process to ensure regulatory review of a new emission source is facilitated through a permit or license application submitted by the new source to the state. The Maine DEP has delegated authority and thus jurisdiction over air emissions produced by the proposed project. The Maine DEP enforces its own regulations as well as EPA's federal requirements. The following sections summarize the applicability of various Maine DEP and federal regulations. The permit review process, performed by the Maine DEP, addresses regulatory requirements for both construction and operation of the new source.

The type of air quality permit that must be obtained depends on whether the proposed facility is designated as a major source or a minor source. This source designation (major or minor) depends on the potential to emit (PTE) for the various pollutant emissions. For a new LNG facility in the state of Maine, if the emissions for any regulated pollutant in an attainment area exceeds 100 tons per year (tpy), then the facility is considered a major source for that pollutant. In addition, if the PTE for any one hazardous air pollutant (HAP) exceeds 10 tpy, or the total of all HAPs exceed 25 tpy, then the facility is considered a major source for HAPs.

All new emission sources located in the OTR are considered to be in a nonattainment area with respect to permitting of $NO_x$ and VOC emissions, and the corresponding major source thresholds for these ozone precursor pollutants are 100 tpy and 50 tpy, respectively.

Although operation of a new LNG terminal would mean additional air emissions from LNG vessels, tugs, and escort boats that visit the terminal, these maritime emissions are excluded from consideration for permit PTE calculation under Maine regulations. As described in Maine DEP Chapter 100, emissions from marine vessels are considered secondary emissions, and secondary emissions are excluded from stationary source permit calculations. The estimated emissions for the LNG terminal and operations are below the thresholds for a major source, and thus the project is considered a minor source. The project is thus required by the state of Maine to obtain a minor source permit. Use of Best Available Control Technology (BACT) is required for all new emission sources in the state of Maine.

To ensure protection for other air quality concerns (e.g., visibility, vegetation damage), the state of Maine requires a new emission source to model their emissions to quantify the impacts. An air model analysis is automatically required for any source with a emissions of 50 tpy for $SO_2$, 250 tpy for CO, 25 tpy for $PM_{10}$, 100 tpy for $NO_x$, 0.6 tpy for lead, or 0.2 tpy for total chromium. The level of impact analysis required for sources where the emissions are below these levels is generally determined by the Maine DEP on a case-by-case basis. At the request of the FERC, an air quality impact analysis was performed for CO, $NO_x$, $PM_{10}$, $PM_{2.5}$, and $SO_2$ emissions from SCVs and vessel activities within the moored safety zone for the Downeast LNG Project. For the purpose of the analysis, $PM_{2.5}$ emissions are assumed to be equal to $PM_{10}$ emissions. Under NEPA we require that air quality impacts be evaluated based on the combination of primary and secondary emissions related to the project. Additional discussion of this air impact analysis is provided in section 4.11.1.5.

**State Permit Application**

To comply with Maine DEP Chapter 115 requirements, on December 5, 2006 Downeast submitted a minor source air emissions permit (i.e., license) application. This permit application was withdrawn by Downeast in November 11, 2007 and Downeast has estimated that the revised permit application would be resubmitted with the other state applications following issuance of the final EIS. The permit process requires a thorough review of project emissions to demonstrate they comply with applicable state and federal regulations and requirements, including the Maine SIP, however, the final permit should reflect the equipment and emissions identified in this final EIS. State rules require that project construction activities cannot begin until the permit application has been approved and because the state is within the OTR. Areas within the OTR must comply with the federally enforceable SIP. To ensure that the final permit reflects the analysis within this final EIS, **we recommend that:**

- **<u>Prior to construction of the LNG terminal</u>, Downeast should file with the Secretary a copy of its final air permit from the Maine DEP. The permitted emissions should be consistent with the emissions of criteria pollutants, GHGs, and HAPs analyzed in the final EIS.**

**Federal Requirements**

<u>New Source Review/Nonattainment New Source Review</u>

New Source Review (NSR) is a major source permit review process that applies to the construction and operation of new and modified stationary sources in nonattainment areas to ensure attainment of NAAQS. The goal of NSR is to assure that new major source emissions do not significantly worsen air quality, and that advances in pollution control technology occur concurrently with industrial expansion. NSR requirements do not apply to the project because the project is designated under Maine regulations as a minor source.

Federal Class I Areas

Federal Class I areas include international parks, national wilderness areas, national parks, and national memorial parks that are given special protection. Federal Class I areas are designated in 40 CFR 81. If a new major source is located near a Class I area, then the air quality impacts (i.e., expected increases in air pollutant concentrations caused by the project) must be evaluated based on the more stringent thresholds. The Class I areas located near the project are shown in table 4.11.1.3-1. Because the project is a minor source, the major source requirements for protection of Federal Class I areas do not apply. However, under NEPA we are tasked with disclosing the individual and cumulative impacts from the project.

We requested that Downeast coordinate with the Domtar Paper Company and Calais LNG[26], in cooperation with the Maine DEP, the Department of the Interior, and the Department of Agriculture Forest Service, to provide a cumulative air impact analysis consistent with the guidelines published in the Federal Land Managers Air Quality Related Values Workgroup (FLAG) Report. The results of the cumulative air analysis are described later in this section.

TABLE 4.11.1.3-1

**Distance from Downeast LNG Site to Nearby Federal Class I Areas**

| Class I Area | Distance from Project (miles) |
|---|---|
| Moosehorn Wilderness Area - Baring Unit (MWABU) | 8.5 |
| Moosehorn Wilderness Area - Edmunds Unit (MWAEU) | 14.8 |
| Roosevelt Campobello International Park (RCIP) | 14.4 |
| Acadia National Park | 66.2 |

Prevention of Significant Deterioration

Prevention of Significant Deterioration (PSD) is an emissions permit review process designed to ensure that new major sources do not excessively compromise air quality for attainment areas. The major source threshold for PSD review for LNG facilities is 250 tpy of any criteria pollutant. The PSD major source threshold for GHGs is 100,000 tpy of $CO_{2e}$. The direct emissions from the Downeast LNG Terminal would be above these thresholds, thus the terminal would be required to apply for a PSD permit.

[26] Calais LNG previously proposed to construct an LNG import terminal and related natural gas facilities (Calais LNG Project) by the St. Croix River in Washington County, near the city of Calais, Maine. This project would include a 20.7-mile-long natural gas pipeline to connect the LNG terminal with M&NE system near Baileyville, Maine. The Commission has dismissed the Calais LNG application and the project is no longer considered a proposed project.

Title V Operating Permit

New major sources are required to obtain a Title V Part 70 operating permit. The Title V Part 70 permit process is designed to ensure that rules and regulations associated with air emissions are adequately followed. If a facility's PTE exceeds the criteria pollutant (100 tpy) or HAP thresholds (10 tpy of any single HAP or 25 tpy of all HAPs), the facility is considered a major source. Beginning July 1, 2011, facilities that emit at least 100,000 metric tpy (tonnes) $CO_{2e}$ will be subject to Title V permitting requirements. Title V Part 70 requirements apply to the Downeast LNG Project because the project is a major source of GHG.

New Source Performance Standards

The New Source Performance Standards (NSPS) are codified in 40 CFR Part 60. NSPS apply to new equipment used in specific source categories. NSPS that could potentially apply to the project are discussed below.

| Project Feature | NSPS Discussion |
|---|---|
| LNG Storage Tanks (160,000 $m^3$ each) | NSPS Subpart Kb applies to new vessels that store volatile organic liquids; however, vessels that store only methane are specifically excluded from the NSPS Subpart Kb requirements. Since the LNG storage tanks would store only methane, Subpart Kb requirements do not apply. |
| Diesel Storage Tanks | NSPS Subpart Kb also applies to fuel tanks with a storage capacity greater than 10,567 gallons. The project would include two diesel storage tanks; however, the capacity of these tanks is less than 10,567 gallons; therefore, NSPS Subpart Kb requirements do not apply to the diesel tanks. |
| Submerged Combustion Vaporizers (SCVs) | NSPS Subparts Db and Dc apply to steam generation units. However, an SCV that transfers heat to a heat transfer medium by direct contact or intermixing of the combustion gases, the heat transfer medium is not considered a steam generation unit under Subparts Db and Dc. The project SCVs satisfy this exclusion; therefore, NSPS Subparts Db and Dc do not apply. |
| 1,000 kW Emergency Generator and Fire Pumps | EPA promulgated NSPS requirements (Subpart IIII – "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines") to reduce emissions of air pollutants from stationary compression ignition (CI) internal combustion engines (ICE), such as the 1,000-kW emergency generator and the eight emergency fire pumps to be located at the LNG terminal.<br><br>The final rule would reduce $NO_x$, PM, $SO_2$, CO, and HC emissions gradually from now to year 2015. New stationary diesel engines (those constructed or ordered after July 11, 2005) are required to comply with the final rule.<br><br>Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder that use diesel fuel must only use diesel fuel that satisfies the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, which requires that the diesel fuel have a maximum sulfur content of 15 ppm. |

National Emission Standard for Hazardous Air Pollutants

The National Emissions Standards for Hazardous Air Pollutants (NESHAPs) are emissions standards regulated by the EPA for specific HAPs not included in the NAAQS. NESHAPs are established on the basis of source category (source category means the type of industry or process that generates the HAPs). A minor HAP emission source emits less than 10 tpy of any single HAP and less than 25 tpy of all HAPs combined while a source that exceeds these thresholds is designated as a major HAP source. Major HAP sources are subject to Maximum Available Control Technology (MACT) standards to minimize HAP emissions.

The EPA has not issued any NESHAPs for LNG projects pursuant to the CAA. However, HAP emissions for the LNG terminal and sendout pipeline are well below the major source thresholds. Accordingly, MACT standards would not apply to the project.

General Duty Clause and Risk Management Plan

The General Duty Clause of the CAA states that the owners and operators of a stationary source that produces, processes, handles, or stores one or more extremely hazardous substance have a general duty to identify the hazards which may result from the release of those hazardous substances. In addition, based on appropriate hazard assessment methods, the owners and operators must design and maintain a safe facility, ensure adequate prevention methods, and minimize consequences in the event an accidental release does occur. These efforts must be formalized into a Risk Management Plan (RMP) that is made available to local and state agencies and to the public.

In year 2005, the EPA Office of General Counsel clarified in a memorandum that "the language of the statute and the legislative history demonstrate that Congress did **not** intend the general duty clause and RMP regulations to apply to LNG facilities to the extent they transport, or store incident to transportation, extremely hazardous substances, including methane." Therefore, the requirements of the General Duty Clause and RMP do not apply to the project.

General Conformity

A conformity analysis is required when a federal action will generate emissions exceeding conformity threshold levels of pollutants for which an air basin is designated as nonattainment. According to Section 176(c)(1) of the CAA (40 CFR Section 51.853), a federal agency cannot approve or support activity that does not conform to an approved SIP. At this time, General Conformity does not apply to federal actions in Washington County, Maine, which is attaining all NAAQS and does not have a maintenance plan.

Control of Air Pollution from Marine Compression Ignition Engines

The EPA emission control program for marine engines consists of several sets of standards which vary based on engine type (gasoline or diesel powered) and size. These standards apply to newly manufactured engines installed on vessels that operate under the flag of the United States; however, all LNG vessels currently in service are foreign flagged vessels and not subject to this regulation. Therefore, the EPA emission control requirements would likely have little effect to reduce pollutant emissions associated with LNG vessel activity, but may reduce emissions from escort vessels and tugs at the LNG terminal.

The International Maritime Organization (IMO) is the primary regulatory agency that develops regulations for the control of air pollution generated by international marine activities. The IMO published the MARPOL in 1973 and modified it in 1978. Since then, the IMO has developed six annexes concerned with pollution from maritime vessels. MARPOL Annex VI, "Regulations for the Prevention of Air Pollution from Ships" went into force in May of year 2005. Since that time it has been ratified by 53 nations that collectively represent nearly 82 percent of the global marine tonnage. Annex VI applies to all ships registered to the nations that have ratified the legislation, and ships that operate in waters controlled under the jurisdiction of nations that have ratified the legislation. On October 10, 2008, the IMO issued a revised Annex VI, which includes restrictions on the sulfur content of marine fuels. For territorial waters off the United States, the current maximum sulfur content of fuel is 4.5 percent, which is applicable until 2012. In 2012, the maximum sulfur content is 3.5 percent and in 2020 the sulfur content is restricted to 0.5 percent. MARPOL Annex VI was adopted by the U.S. Government on July 21, 2008 and Downeast and associated LNG vessels would be required to comply with the Annex VI emission standards.

In March 2010, the IMO designated specific areas of our coastal waters as part of an Emission Control Area (ECA). The proposed ECA would extend 200 nautical miles from the coastal baseline. EPA has estimated this new ECA designation will lead to a 96 percent reduction in sulfur in marine fuels and reduce particulate matter and NOx emissions by 85 percent and 80 percent, respectively. To achieve these reductions, vessels must use fuel with no more than 1,000 parts per million (ppm) sulfur beginning in 2015, and new vessels will have to use advanced emission control technologies beginning in 2016. In the United States and Canada combined, the ECA is expected to reduce emissions of NOx by 320,000 tons, $PM_{2.5}$ by 90,000 tons, and SOx by 920,000 tpy, which is 23 percent, 74 percent, and 86 percent below current levels, respectively.

In June 2009, the EPA proposed more stringent exhaust emission standards for the largest marine diesel engines which propel Category 3 engines (these are large engines, greater than or equal to 30 liters per cylinder). These proposed CAA standards are part of a coordinated strategy to address emissions from all maritime vessels which adversely impact air quality in the United States.

#### 4.11.1.4 Greenhouse Gas Reporting

On October 30, 2009, the EPA published the final Mandatory Reporting of Greenhouse Gases rule, establishing the Greenhouse Gas Reporting Program (GHGRP) codified in Title 40 CFR Part 98. The GHGRP has required large direct emitters of GHGs, and certain suppliers (e.g., of fossil fuels, petroleum products, industrial gases and $CO_2$) to report GHG information annually. Subpart W of Title 40 CFR Part 98 applies to petroleum and natural gas systems, including: both onshore and offshore petroleum and natural gas production; onshore natural gas processing; natural gas transmission compression; underground natural gas storage; and liquefied natural gas storage, import and export facilities that emit greater than or equal to 25,000 metric tons of GHG, as $CO_{2e}$, per year.

Because combustion-related GHG emissions from the Downeast LNG Project operations are expected to exceed 25,000 metric tpy, Downeast may be required to comply with all applicable requirements of the rule. If actual GHG emissions from the proposed project are equal to or greater than 25,000 metric tpy, Downeast would be required to comply with all applicable requirements of 40 CFR Part 98.

**State Requirements**

The Maine DEP Bureau of Air Quality (BAQ) is the lead air permit authority for the proposed LNG project. Any new facility is required to obtain an air quality permit (license) before construction is initiated. Facilities can trigger additional review by EPA if emissions exceed the major source thresholds listed in 40 CFR Section 52.21. Maine DEP Chapter 375 regulations deal with state review to determine compliance with the "no adverse effect to the natural environment" standard of the Site Location Law. Chapter 375.1 addresses "No Unreasonable Adverse Effect on Air Quality" considerations. Other state requirements for air quality are listed below.

| Maine DEP BAQ Requirement | Description |
|---|---|
| Chapter 101 Section (2)(B)(1)(f) | Visible emission standards |
| Chapter 101 Section (2)(B)(6) | Visible emissions standards (fuel burning sources that are restricted to less than 20 percent capacity on an annual basis). |
| Chapter 103 Section (2)(B)(1)(a & b) | Particulate emissions standards |
| Chapter 106 Section (2)(A)(2) | Sulfur in liquid fossil fuels |
| Chapter 115 Section (3)(E)(5)(e) | Annual air emission license fees (payment thereof) |
| Chapter 115 Section (3)(E)(5)(g) | Maintain and operate all emission units, air pollution control and monitoring systems required by the air emission license in a manner consistent with good air pollution control practice for minimizing emissions. |
| Chapter 115 Section (3)(E)(5)(h) | Maintain sufficient records to accurately document compliance with emission standards and license conditions and maintain such records for a minimum of six (6) years. The records shall be submitted to the Maine DEP upon written request. |
| Chapter 135 Section (3) | Hexavalent chromium particulate emissions standard (only if total aggregate chromium concentration in distillate oil is in excess of 500 ppm). |
| Chapter 137 Section (3)(A) | File an emission statement (for criteria pollutants) with the Maine DEP on an annual basis. |
| Chapter 137 Section (3)(C) | File an emission statement (for HAPs) with the Maine DEP every three years. |
| Chapter 148 | Emissions from Smaller-Scale Electric Generating Resources |

| Maine DEP BAQ Requirement | Description |
|---|---|
| Chapter 101 Section (2)(B)(4) | Visible emissions from a fugitive emission source shall not exceed opacity of 20 percent, except for no more than five minutes in any one hour period. Compliance shall be determined by an aggregate of the individual fifteen second opacity observations which exceed 20 percent in any one hour. |
| Chapter 115 Section (3)(E)(5)(d) | Establish and maintain a continued program of BMPs for suppression of fugitive particulate matter during any period of construction, reconstruction, or operation which may result in fugitive dust, and submit a description of the program to the BAQ upon request. |

In Maine, dispersion models or analysis of other air quality impacts (visibility, vegetation damage, etc.) are required to evaluate a new major source or at a new minor source with a PTE that exceeds 50 tpy for $SO_2$, 250 tpy for CO, 25 tpy for $PM_{10}$, 100 tpy for $NO_2$, 0.6 tpy for lead, or 0.2 tpy for total chromium. The level of impact analysis required for smaller sources is generally determined by Maine DEP on a case-by-case basis based on various factors, including existing air quality levels; the adequacy of proposed stack heights to avoid high impacts on local areas; the proximity to Class I areas, integral vistas, or nonattainment areas; the extent to which available air quality may be limited due to the consumption of increment by other sources; and the availability of existing analytic air model results for similar sources. Maine DEP can also require post-construction monitoring if it determines there is a need.

#### 4.11.1.5 Potential Impacts and Mitigation

##### 4.11.1.5.1 Waterway for LNG Marine Traffic

No LNG vessels would be present during construction; therefore, there are no adverse effects anticipated. During operations, LNG vessels would arrive (and egress in reverse order) at the terminal through the Head Harbour, Western Passage, and Passamaquoddy Bay. The total distance from the seaward Pilot Station to the import terminal berth is 16.6 nautical miles. Pilots would board the vessel at the Pilot Station located about 1.5 nautical miles offshore of East Quoddy Head.

During normal operating conditions some impact on air quality would occur along the entire waterway from the territorial seas to the terminal. We do not know the magnitude of current emissions from current ship traffic, thus we cannot quantitatively determine the percentage increase in air impacts due to the increase in ship traffic from LNG vessels and support vessels. However, the emissions affecting any localized area would be temporary as the LNG tanker and support vessels make the transit. The majority of the route is between 1,500 and 3,000 feet from the shore. At locations closer than 1,500 feet, residences may smell vessel exhaust odors and have short term impacts in excess of the NAAQS and Maine AAQS. At locations farther away, the distance would allow for considerable pollutant dispersion/dilution. Thus while we cannot quantify the impacts, we do expect a minor decrease in air quality along the waterway. The impacts (based upon wind speed, direction, number of LNG tanker support vessels, and fuel mixtures) may be considerably above ambient air quality levels, but for very short periods in any one location. Estimated criteria pollutant and GHG emissions from vessel activities are shown in table 4.11.1.5.1-1. These emission totals include estimated emissions from inbound transit along the waterway, time at berth, outbound transit, and standby diesel generator operations.

TABLE 4.11.1.5.1-1

**Criteria Pollutant and Greenhouse Gas Emissions due to Vessel Activity Associated with Terminal Operations (tons per year)**

| Emissions | Vessels | Tugs | Escort a/ | Total |
|---|---|---|---|---|
| $CO_2$ | 7590 | 1872 | 58 | 9521 |
| $CH_4$ | 0.07 | 0.2 | 0.01 | 0.28 |
| $N_2O$ | 0.524 | 0.1 | 0.002 | 0.626 |
| $CO_{2e}$ b/ | 7748 | 1907 | 59 | 9715 |
| NOx | 23.2 | 22 | 0.8 | 46.0 |
| CO | 2.9 | 13.6 | 0.1 | 16.6 |
| $PM_{10}$ | 0.54 | 1.3 | 0.03 | 1.87 |
| $PM_{2.5}$ | 0.24 | 1.3 | 0.03 | 1.57 |
| VOC | 0.92 | 1.2 | 0.02 | 2.14 |
| $SO_2$ | 3.60 | 1.7 | 0.05 | 5.35 |

a/ One Coast Guard escort vessel per delivery was assumed to estimate potential emissions.
b/ $CO_{2e}$ emissions were calculated using the following global warming potentials: 1 for $CO_2$, 25 for $CH_4$, and 298 for $N_2O$.

$CH_4$ = methane.

### 4.11.1.5.2 LNG Terminal

#### Construction

During construction, a temporary reduction in ambient air quality may result from emissions and fugitive dust generated by construction equipment. Fugitive dust emission levels would vary in relation to moisture content, composition, and volume of soils disturbed. Fugitive dust and other emissions from construction activities generally do not result in a significant increase in regional pollutant levels, although local pollutant levels could increase temporarily. Downeast would implement dust control measures as necessary during certain construction activities, such as transporting soil or rock, trenching, grading, pile driving, and use of access roads. These measure would include frequent water applications on access roads and in construction work areas; vehicle speed restrictions; use of gravel or asphalt at site exit points to remove dirt from tires and tracks; and replanting disturbed areas as soon as possible following construction.

Criteria pollutant and GHG emissions during construction equipment would result from combustion of gasoline and diesel fuels, primarily $NO_x$, CO, VOCs, $PM_{10}$, $PM_{2.5}$, $SO_{2,}$ and $CO_{2e}$, as well as small amounts of HAPs.

Downeast anticipates that construction of the entire project would take a total of about 35 months. The first part of this process would be terminal site work and foundation preparation for the LNG storage tanks. Once the tank foundations are in place, work would begin on tank construction, terminal buildings, and the marine terminal. It is anticipated that the LNG storage tank construction would take about 30 months from the start of site work. The other terminal facilities would be constructed in about 18 months with marine construction taking around

6 months.  Sendout pipeline construction would take about 9 months.  Construction activities that may generate air pollutant emissions include:

- tree and brush removal;
- topsoil removal and storage;
- excavation and backfill;
- roadway construction and maintenance;
- erection of facilities (e.g., tanks, structures, process equipment); and
- construction support (deliveries, portable lights, etc.).

Construction emissions would be produced by:

- heavy duty diesel equipment such as excavators, dozers, and cranes (includes both exhaust emissions and fugitive dust emissions);
- delivery vehicles, fuel trucks, water trucks, dump trucks (includes both exhaust emissions and fugitive dust emissions);
- marine equipment, such as tugs, other support vessels, and cranes;
- portable engines such as compressors, welders, light tower systems, generators, and pile hammers; and
- employee-owned vehicles, both on-site and from inbound commute (includes both exhaust emissions and fugitive dust emissions).

We received a comment from the EPA relative to the public health impacts from diesel exhaust.  As demonstrated in table 4.11.1.5.2-1, the criteria and HAP emissions due to terminal construction would be relatively low, and these effects would be distributed over four years.  All emissions would be only a fraction of the major emission source threshold levels.  An estimate of the combined GHG emissions from commuter vehicles, on-site vehicles, and diesel-fired construction equipment during an assumed 35-month construction period spread over four calendar years is shown in table 4.11.1.5.2-2.  To address these EPA concerns, prior to the start of construction activities Downeast would incorporate contract language (summarized below) to address the public health impacts from the diesel exhaust of construction vehicles and equipment:

- All motor vehicles and/or construction equipment (both on-highway and non-road) shall comply with all pertinent State and Federal regulations relative to exhaust emission controls and safety;

- All diesel-powered, non-road construction equipment and generators with engine horsepower (hp) of 60 hp and above that are on the project or are assigned to the contract for a period in excess of 30 consecutive calendar days, shall (1) operate on Clean Fuels or (2) be modified through the installation of Retrofit Emission Control Devices to achieve a reduction in the emissions of CO, HC, $NO_x$, and $PM_{10}$;

- Retrofit Emission Control Devices shall consist of oxidation catalysts, or similar retrofit equipment control technology that (1) is included on the EPA Verified Retrofit

Technology List and (2) is verified by EPA or certified by the manufacturer to provide a minimum emissions reduction of 20 percent $PM_{10}$, 40 percent CO, and 50 percent HC;

- Clean Fuels shall consist of diesel fuel that (1) can be used without engine modification (2) is certified to provide a minimum emissions reduction of 30 percent $PM_{10}$ and 10 percent NOx when compared to Number 2 Diesel Fuel, and (3) is included on the California Air Research Board Verification List;

- Construction shall not proceed until the contractor submits a certified list of the non-road diesel powered construction equipment that will be retrofitted with emission control devices or that will use Clean Fuels. The list shall include (1) the equipment number, type, make, and contractor or subcontractor name (2) the emission control device make, model, and EPA verification number and/or (3) the type and source of fuel to be used;

- The construction contractor shall submit monthly summary reports, update the same information stated above, and include certified copies of the Clean Fuel delivery slips for the report time period, and note which vehicles received the fuel. The addition or deletion of non-road diesel equipment shall be included on the monthly report; and

- Downeast shall require coordination among the contractors and its own onsite environmental management to establish appropriate zones to stage diesel powered vehicles that await to load or unload material at the contract area. These zones will be located where the diesel emissions from the trucks will have minimum impact on abutters and the general public. Idle of delivery and/or dump trucks or other diesel powered equipment will not be permitted for periods of non-active use and will comply with State anti-idle laws.

In addition, blasting activities would be required on certain land portions of the site, especially to develop roadway access to the marine receiving terminal and to prepare for construction of the slab foundations for the LNG tanks. Blasting activities would occur in the first year of construction but would generally be performed in a manner to minimize dust emissions. For this reason, air emissions of $PM_{10}$ and $PM_{2.5}$ from blasting activities are expected to be minimal.

Fugitive dust generation would be primarily a function of the area of construction, silt and moisture contents of the soil, wind speed, frequency of precipitation, amount of vehicle traffic, vehicle types and paved roadway characteristics. Fugitive dust may be produced during all phases of construction. Emissions would be greater over the first 12 months and in areas of fine-textured soils. If nuisance conditions result from fugitive dust generated by construction activities, Downeast would prepare a dust control plan to minimize dust generation. Ground surfaces would be watered as necessary to minimize generation of fugitive dust. No dredging activities are proposed. An off-site concrete batch plant would provide the entire concrete requirements of the land-side construction and a portion of the marine terminal requirements. The remainder of the marine construction requirements would be satisfied by concrete from other sources and transported by barge. Emissions from the off-site plants are not considered part of the terminal construction emissions.

TABLE 4.11.1.5.2-1

**Estimated Criteria and HAP Emissions from LNG Terminal Construction**

| Year a/ | Emission Category | Total Emissions of Category (tpy) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | $NO_x$ | VOC | CO | $SO_2$ | $PM_{10}$ | $PM_{2.5}$ | Total HAPs |
| **One** | Construction Equipment b/ | 27.48 | 1.48 | 9.20 | 0.02 | 1.34 | 1.30 | 1.01 |
| | Commute/Delivery Vehicles | 0.19 | 0.09 | 1.38 | 0.00 | 0.01 | 0.00 | 0.03 |
| | On-site Vehicle Engines | 0.28 | 0.05 | 0.66 | 0.00 | 0.01 | 0.01 | 0.02 |
| | Earth Movement Fugitives | N/A | N/A | N/A | N/A | 7.84 | 2.11 | N/A |
| | On-site Wind Erosion | N/A | N/A | N/A | N/A | 0.71 | 0.11 | N/A |
| | On-site Vehicle Re-suspended PM | N/A | N/A | N/A | N/A | 27.52 | 2.97 | N/A |
| | **Total** | **27.95** | **1.62** | **11.25** | **0.03** | **37.42** | **6.48** | **1.06** |
| **Two** | Construction Equipment b/ | 45.29 | 2.74 | 10.74 | 0.04 | 1.88 | 1.82 | 1.64 |
| | Commute/Delivery Vehicles | 0.84 | 0.64 | 9.95 | 0.01 | 0.03 | 0.02 | 0.21 |
| | On-site Vehicle Engines | 0.34 | 0.05 | 0.64 | 0.00 | 0.01 | 0.01 | 0.02 |
| | Earth Movement Fugitives | N/A | N/A | N/A | N/A | 1.18 | 0.26 | N/A |
| | On-site Wind Erosion | N/A | N/A | N/A | N/A | 0.774 | 0.12 | N/A |
| | On-site Vehicle Re-suspended PM | N/A | N/A | N/A | N/A | 13.80 | 1.40 | N/A |
| | **Total** | **46.47** | **3.42** | **21.34** | **0.05** | **17.68** | **3.62** | **1.87** |
| **Three** | Construction Equipment b/ | 44.02 | 2.39 | 9.10 | 0.04 | 1.53 | 1.49 | 1.59 |
| | Commute/Delivery Vehicles | 0.75 | 0.59 | 9.49 | 0.01 | 0.03 | 0.02 | 0.20 |
| | On-site Vehicle Engines | 0.26 | 0.05 | 0.59 | 0.00 | 0.01 | 0.01 | 0.01 |
| | Earth Movement Fugitives | N/A | N/A | N/A | N/A | 1.18 | 0.26 | N/A |
| | On-site Wind Erosion | N/A | N/A | N/A | N/A | 0.12 | 0.02 | N/A |
| | On-Site Vehicle Re-suspended PM | N/A | N/A | N/A | N/A | 11.55 | 1.17 | N/A |
| | **Total** | **45.03** | **3.02** | **19.18** | **0.05** | **14.43** | **2.95** | **1.80** |
| **Four** | Construction Equipment b/ | 2.19 | 0.16 | 0.55 | 0.00 | 0.14 | 0.13 | 0.08 |
| | Commute/Delivery Vehicles | 0.10 | 0.05 | 0.72 | 0.00 | 0.00 | 0.00 | 0.02 |
| | On-site Vehicle Engines | 0.07 | 0.02 | 0.22 | 0.00 | 0.00 | 0.00 | 0.01 |
| | Earth Movement Fugitives | N/A | N/A | N/A | N/A | 0.00 | 0.00 | N/A |
| | On-site Wind Erosion | N/A | N/A | N/A | N/A | 0.02 | 0.00 | N/A |
| | On-site Vehicle Re-suspended PM | N/A | N/A | N/A | N/A | 3.30 | 0.33 | N/A |
| | **Total** | **2.36** | **0.22** | **1.48** | **0.00** | **3.45** | **0.47** | **0.10** |

a/ We have used the schedule Downeast provided in its application to estimate construction emissions.
b/ Construction equipment includes offshore marine vessels and equipment.

| TABLE 4.11.1.5.2-2<br>**Estimated Greenhouse Gas Emissions from Terminal Construction** | |
|---|---|
| **Greenhouse Gas** | **Terminal Construction (Years One- Four) (tpy)** |
| $CO_2$ | 12,437 |
| $CH_4$ | 0.67 |
| $N_2O$ | 0.31 |
| **Total Emissions in $CO_2$ equivalence** | **12,545** |

## Operation

The main source of emissions during operations at the LNG terminal would be from the three SCVs that would operate on a regular basis. The fourth SCV is a backup. All other emissions due to LNG terminal operation would be from maintenance activities or potential emergency conditions. As shown in table 4.11.1.5.2-3, estimated criteria pollutant emissions would be well below the threshold of a major source. Combined HAP emissions are 3.1 tpy, and the maximum single HAP emission is 3 tpy (hexane); therefore, MACT is not required. Estimated GHG emissions are shown in table 4.11.1.5.2-4.

TABLE 4.11.1.5.2-3

**Criteria Pollutant Emissions due to LNG Terminal Operations (Stationary Sources Only)**

| **Emission Unit(s)** | **Number of Units** | **PTE (tpy)** | | | | | |
|---|---|---|---|---|---|---|---|
| | | **$NO_x$** | **CO** | **$PM_{10}$** | **$PM_{2.5}$** | **VOC** | **$SO_2$** |
| Submerged Combustion Vaporizers (SCVs) | 4 | 61.2 | 50 | 2.4 | 2.4 | 13.2 | 1.2 |
| 1,000-kW Emergency Generator | 1 | 3.88 | 0.09 | 0.02 | 0.02 | 0.04 | 0.13 |
| Diesel Fire Pump | 1 | 0.73 | 0.02 | 0.00 | 0.00 | 0.06 | 0.01 |
| Seawater Fire Pump | 7 | 5.08 | 0.14 | 0.03 | 0.03 | 0.41 | 0.06 |
| Emergency Venting | 1 | -- | -- | -- | -- | 3 | -- |
| **Total** | | **70.9** | **50.3** | **2.5** | **2.5** | **16.7** | **1.4** |

TABLE 4.11.1.5.2-4

**Estimated Greenhouse Gas Emissions due to LNG Terminal Operations (Stationary Sources Only)**

| **Emissions Unit** | **Number of Units** | **$CO_2$** | **$NH_4$** | **$N_2O$** | **$CO_{2e}$** |
|---|---|---|---|---|---|
| Submerged Combustion Vaporizers (SCVs) | 4 | 197,500 | 3.3 | 3.3 | 198,600 |
| 1,000-kW Emergency Generator | 1 | 401 | 0.02 | 0.00 | 402 |
| Diesel Fire Pump | 1 | 27 | 0.00 | 0.00 | 27 |
| Seawater Fire Pump | 7 | 188 | 0.01 | 0.00 | 189 |

Vessel Emissions

During operation of the LNG terminal one LNG vessel could arrive every five to seven days in the winter, and one vessel could arrive every eight to ten days in the summer. The entire sequence from arrival to departure would last around 21 hours. The LNG vessel would use onboard pumps to transfer LNG to the storage tanks on land. Maximum expected time to unload the LNG is about 13 hours. Anticipated vessel emissions associated with terminal operations are presented in table 4.11.1.5.1-1. Vessel emissions would be generated by the travel of the LNG import vessel, three or four tugs, and an unspecified number of escort vessels within the safety/security zone. Emissions in the fixed zone (vessel moored) would be generated by the LNG import vessel, one standby tug as the cargo is unloaded, and one escort vessel to enforce the fixed zone. These emissions are considered secondary and are thus not included in the PTE for the LNG terminal permit. Estimated criteria pollutant and GHG emissions from vessel activities are shown in table 4.11.1.5.1-1. These emission totals include estimated emissions from time at berth and standby diesel generator operations while at berth, as well as inbound and outbound transit along the waterway.

#### 4.11.1.5.3 Sendout Pipeline

**Construction**

The Downeast LNG Project would include construction of a 29.8-mile, 30-inch-diameter pipeline that would extend from the project site to the M&NE Baileyville Compressor Station at Baileyville, Maine. Pipeline construction would extend over two years with the most construction taking place during the first year. Construction activities that may generate air pollutant emissions include:

- tree and brush removal;
- topsoil removal and storage;
- excavation, backfill, and compaction; and
- support activities (e.g., water and fuel deliveries).

Pipeline construction emissions would be produced by:

- heavy equipment exhaust;
- light equipment and pick-up truck exhaust;
- delivery vehicle exhaust;
- worker-owned vehicle exhaust;
- fugitive particulate generated by earth-movement activities; and
- fugitive particulate generated by vehicle tires on unpaved surfaces.

Small amounts of air pollutant emissions from worker and delivery vehicle use on public roadways would also be attributable to the construction project. The coating of the pipeline welds would utilize a heat-shrinkable sleeve which produces VOC emissions, but the quantities are negligible. Ground surfaces would be watered to minimize generation of dust. Estimates of annual criteria and HAP emissions due to sendout pipeline construction are shown in table 4.11.1.5.3-1. We received a comment from the EPA relative to the public health impacts from diesel exhaust. As table 4.11.1.5.3-1 shows, all anticipated emissions from pipeline construction would be only a fraction of the PSD major emission source threshold levels. Nevertheless, we encourage Downeast to use new equipment, retrofit existing equipment, and/or use clean fuels to reduce diesel emissions. An estimate of the combined GHG emissions from pipeline construction activities during the two-year construction period is shown in table 4.11.1.5.3-2.

TABLE 4.11.1.5.3-1

**Estimated Emissions from Construction of Sendout Pipeline in Washington County, Maine**

| Year a/ | Emission Category | Total Emissions of Category (tpy) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | $NO_x$ | VOC | CO | $SO_2$ | $PM_{10}$ | $PM_{2.5}$ | Total HAPs |
| **One** | Construction Equipment | 116.1 | 5.63 | 35.9 | 0.10 | 5.33 | 5.17 | 4.33 |
| | Worker's Vehicles | 0.62 | 0.45 | 7.01 | 0.01 | 0.02 | 0.01 | 0.16 |
| | Off-Road and Mobile Vehicle Fugitives | 0.00 | 0.00 | 0.00 | 0.00 | 8.31 | 1.02 | 0.00 |
| | Materials Handling Fugitive Emissions | 0.00 | 0.00 | 0.00 | 0.00 | 2.29 | 1.68 | 0.00 |
| | **Total** | **116.70** | **6.09** | **42.9** | **0.11** | **16.0** | **7.88** | **4.48** |
| **Two** | Construction Equipment | 15.9 | 0.89 | 4.40 | 0.01 | 0.81 | 0.79 | 0.60 |
| | Worker's Vehicles | 0.07 | 0.05 | 0.82 | 0.00 | 0.00 | 0.00 | 0.02 |
| | Off-Road and Mobile Vehicle Fugitives | 0.00 | 0.00 | 0.00 | 0.00 | 3.06 | 0.40 | 0.00 |
| | Materials Handling Fugitive Emissions | 0.00 | 0.00 | 0.00 | 0.00 | 0.51 | 0.30 | 0.00 |
| | **Total** | **15.9** | **0.94** | **5.22** | **0.01** | **4.39** | **1.49** | **0.62** |

a/ We have used the schedule Downeast provided in its application for the purposes of estimating construction emissions.

TABLE 4.11.1.5.3-2

**Estimated Greenhouse Gas Emissions from Pipeline Construction Activities (tons)**

| Greenhouse Gas | Pipeline Construction (Years One and Two) |
|---|---|
| $CO_2$ | 12,900 |
| $CH_4$ | 0.72 |
| $N_2O$ | 0.33 |
| **Total Emissions in $CO_2$ equivalence** | **13000** |

## Operation

The main source of emissions during operation of the 29.8-mile-long sendout pipeline would be due to fugitive pipeline emissions (very minor leakage) at pipe valves and connections. These emissions would be small and would be distributed over a large area, and are therefore negligible.

#### 4.11.1.5.4 Operational Regional Air Quality Impact

To determine the impact on local and regional air quality in the area, as well as to determine the impacts to Class I areas, the EPA-approved AERMOD air quality dispersion model was applied to evaluate air quality impacts attributable to:

- the Downeast LNG Project stationary emission sources and related maritime vessel emissions; and
- combined emissions from the Downeast LNG Project operations, Domtar Paper Plant operations, and potential operations at the previously proposed Calais LNG facility.

Downeast consulted with the Maine DEP, the NPS, and the FWS to coordinate the technical approach for the Class I air modeling evaluation and receive guidance on the impact evaluation for nearby Class I areas (RCIP, MWABU, and MWAEU). At the request of the NPS, St. Croix Island, located near the town of Calais on the St. Croix River, an International Historic Site managed by the NPS, was also evaluated. The guidance from the Maine DEP/NPS/FWS consultations was incorporated into the Class I air modeling evaluation.

Model inputs for the Domtar Paper Plant sources were provided by Maine DEP. Model inputs for the Calais LNG facility were extracted from the AERMOD model input files that Calais LNG provided to Maine DEP as part of their minor source air emissions license application submitted in January 2010. For conservatism, all four of the planned SCVs at the Downeast LNG facility were assumed to operate continuously (8760 hours per year), even though one of the SCVs is a standby unit and the other three units would not operate continuously. Estimated annual emissions from the Downeast LNG Project operations and associated vessel activities are shown in table 4.11.1.5.5-1. Estimated annual emissions associated with the previously proposed Calais LNG and Domtar facilities are shown in tables 4.11.1.5.5-2 and 4.11.1.5.5-3, respectively.

TABLE 4.11.1.5.5-1

**Estimated Annual Emissions from Downeast LNG Terminal Operations and Associated Vessel Activities**

| Pollutant | Terminal Operations (tpy) | Vessel Activities (tpy) | Total (tpy) | Portion from Vessel Activities |
|---|---|---|---|---|
| CO | 50.3 | 16.6 | 66.9 | 24.8% |
| $NO_x$ | 70.9 | 46.0 | 117 | 39.3% |
| $PM_{10}$ | 2.5 | 1.87 | 4.37 | 42.8% |
| $PM_{2.5}$ | 2.5 | 1.57 | 4.07 | 38.6% |
| $SO_2$ | 1.4 | 5.35 | 6.75 | 79.3% |
| VOC | 16.7 | 2.14 | 18.8 | 11.4% |

TABLE 4.11.1.5.5-2

**Estimated Annual Emissions from Calais LNG Terminal Operations and Associated Vessel Activities**

| Pollutant | Terminal Operations (tpy) | Vessel Activities (tpy) | Total (tpy) | Portion from Vessel Activities |
|---|---|---|---|---|
| CO | 84.2 | 13.6 | 97.8 | 13.9% |
| $NO_2$ | 147 | 152 | 299 | 50.9% |
| $PM_{10}$ | 22.1 | 6.1 | 28.2 | 21.5% |
| $PM_{2.5}$ | 22.1 | 6.1 | 28.2 | 21.5% |
| $SO_2$ | 1.9 | 55.8 | 57.7 | 96.8% |
| VOC | 16.6 | 5.2 | 21.8 | 23.9% |

TABLE 4.11.1.5.5-3

**Estimated Annual Emissions from Domtar Operations**

| Pollutant | Plant Operations (tpy) |
|---|---|
| CO | 8,070 |
| $NO_x$ | 1,710 |
| $PM_{10}$ | 756 |
| $PM_{2.5}$ | 756 |
| $SO_2$ | 3,560 |

For all areas outside Class I areas, the air quality evaluation is simply a comparison of the predicted pollutant concentrations against the Maine AAQS and the NAAQS to ensure the emissions would not cause (or contribute to) an exceedance of these standards. For Class I areas, the increase in regional pollutant concentrations are compared to significant impact levels (SILs). Ambient pollutant concentration increases below the SILs are not considered to be significant, and those that exceed the SILs may require further analysis or mitigation. SILs for this assessment are listed in table 4.11.1.5.5-4.

TABLE 4.11.1.5.5-4

**Significant Impact Levels (μg/m$^3$)**

| Average | $NO_2$ | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ |
|---|---|---|---|---|
| 3-Hour | NA | NA | NA | 0.48 |
| 24-Hour | NA | 0.27 | 0.08 | 0.07 |
| Annual | 0.03 | 0.08 | 0.04 | 0.03 |

An evaluation was also performed, in cooperation with guidance from the Federal Land Manager, to determine the impact on Air Quality Related Values (AQRVs) at the nearby Class I areas. AQRVs are resources sensitive to air quality and include a wide array of vegetation, soils, water, fish and wildlife, and visibility. The AQRV evaluation includes:

- a deposition evaluation in which nitrogen and sulfur deposition rates are compared to the Deposition Analysis Thresholds (DATs); and
- a visibility evaluation in which plume visibility is measured in terms of perceptibility based on color contrast (Delta-E) and a spectral, green wavelength plume contrast criterion.

$NO_2$ and $SO_2$ deposition impacts in a Class I area are acceptable if they are less than 0.01 kilogram per hectacre per year. Visibility impacts are acceptable if emissions do not cause a short term (one hour) visible plume where the color change (designated as delta-E) exceeds 2.0, and the absolute value of the spectral, green wavelength plume contrast remains less than or equal to 0.05. Visibility impacts are evaluated with the EPA approved VISCREEN software program. VISCREEN analyzes plume transport times up to 12 hours. The potential for visibility plume overlap impacts was also evaluated. The results of the air impact and AQRV evaluations are tabulated and described below for each geographic area of concern.

**Compliance with Ambient Air Quality Standards - Downeast LNG Terminal**

For areas near the facility not in a Class I area, we have estimated the impacts as shown in table 4.11.1.5.5-5. The sum of background pollutant levels and the maximum predicted regional pollutant concentrations for Class II areas attributable to the Downeast LNG Project are well below the MAAQS and NAAQS. All impacts attributable to the Downeast LNG Project only are well below the MAAQS and NAAQS.

TABLE 4.11.1.5.5-5

**Air Quality Impacts to Class II Areas Based on Emissions from Downeast LNG Terminal Operations and Associated Vessel Activities**

| Pollutant | Average | Background Concentration ($\mu g/m^3$) | Maximum Impact ($\mu g/m^3$) | Background + Impact ($\mu g/m^3$) | MAAQS/NAAQS ($\mu g/m^3$) | Exceedance |
|---|---|---|---|---|---|---|
| CO | 1-Hour | 4568 | 417.2 | 4985 | 40,000 | No |
| CO | 8-Hour | 43.8 | 2284 | 2328 | 10,000 | No |
| $NO_2$ | 1-Hour | 47.0 | 77.6 | 124.6 | 188 | No |
| $NO_2$ | Annual | 11.0 | 5.9 | 16.9 | 100 | No |
| $SO_2$ | 1-Hour | 33.0 | 2.0 | 35.0 | 195 | No |
| $SO_2$ | 3-Hour | 24.0 | 1.7 | 25.7 | 1,150 | No |
| $SO_2$ | 24-Hour | 13.0 | 0.7 | 13.7 | 230 | No |
| $SO_2$ | Annual | 5.0 | 0.1 | 5.1 | 57 | No |
| $PM_{10}$ | 24-Hour | 42.0 | 1.5 | 43.5 | 150 | No |
| $PM_{10}$ | Annual | 10.0 | 0.3 | 10.3 | 40 | No |
| $PM_{2.5}$ | 24-Hour | 18.6 | 1.5 | 20.1 | 35 | No |
| $PM_{2.5}$ | Annual | 5.7 | 0.3 | 6.0 | 15 | No |

## Impacts to Class I Areas – Downeast LNG Terminal

Table 4.11.1.5.5-6 shows the maximum predicted increase in ambient pollutant concentrations at nearby Class I areas for comparison with SIL, based on estimated Downeast LNG Project emissions only. All impacts are below the SILs except for the annual $NO_2$ impact at MWABU. It is important to note that although the annual $NO_2$ SIL is exceeded by 23 percent, the prediction was made using all 4 SCVs instead of just the 3 that would be operating, and this should decrease the magnitude of emissions by 25 percent. Because only three SCVs would be operated simultaneously, and less than continually throughout the year, it is likely that the predicted impact would be less than the SIL if the actual SCV emissions were used as an input to the model. As stated previously while St. Croix Island is not a listed Class I area, NPS requested that it be treated as such to determine the air quality impacts on the site. Air quality impacts on Class I areas due to the Downeast LNG Project operations would not be significant.

TABLE 4.11.1.5.5-6

**Comparison of Air Quality Impacts to SILs for Nearby Class I Areas Based on Emissions from Downeast LNG Terminal Operations and Associated Vessel Activities**

| Pollutant | Average | SIL ($\mu g/m^3$) | Maximum Class I Impact ($\mu g/m^3$) | | | |
|---|---|---|---|---|---|---|
| | | | MWABU | MWAEU | RCIP | St. Croix Island |
| $NO_2$ | Annual | 0.03 | **0.037** | 0.02 | 0.02 | 0.029 |
| $SO_2$ | 3-Hour | 0.48 | 0.18 | 0.13 | 0.11 | 0.1 |
| $SO_2$ | 24-Hour | 0.07 | 0.02 | 0.02 | 0.01 | 0.01 |
| $SO_2$ | Annual | 0.03 | 0.001 | 0.0003 | 0.001 | 0.001 |
| $PM_{10}$ | 24-Hour | 0.27 | 0.06 | 0.04 | 0.04 | 0.03 |
| $PM_{10}$ | Annual | 0.08 | 0.002 | 0.001 | 0.001 | 0.002 |
| $PM_{2.5}$ | 24-Hour | 0.08 | 0.06 | 0.04 | 0.04 | 0.03 |
| $PM_{2.5}$ | Annual | 0.04 | 0.002 | 0.001 | 0.001 | 0.002 |

## Impacts from Nitrogen and Sulfur Deposition on Class I Areas – Downeast LNG Terminal

Table 4.11.1.5.5-7 shows the predicted nitrogen and sulfur deposition levels at nearby Class I areas for comparison with DATs (based on Downeast LNG Terminal only). All predicted deposition rates are below the DATs except for nitrogen deposition at St. Croix Island, which exceeds the DAT by only five percent. It is important to note that although the DAT is exceeded, the result is based on the continuous operation of four SCVs. Because only three SCVs would be operated simultaneously, and they would not be operated continually throughout the year, the magnitude of emissions would be about 25 percent less. Therefore, it is likely that the predicted deposition rate would be less than the DAT if the actual SCV emissions were used as an input to the model. Therefore we conclude that deposition impacts on nearby Class I areas at St. Croix Island due to the Downeast LNG Project operations would not be significant.

TABLE 4.11.1.5.5-7

**Deposition Impacts at Nearby Class I Areas Attributable to Downeast LNG Terminal Operations and Associated Vessel Activities**

| Parameter | DAT (kg/ha/yr) | MWABU (kg/ha/yr) | MWAEU (kg/ha/yr) | RCIP (kg/ha/yr) | St. Croix Island (kg/ha/yr) |
|---|---|---|---|---|---|
| Nitrogen Deposition | 0.010 | 0.0020 | 0.0010 | 0.0060 | 0.0105 |
| Sulfur Deposition | 0.010 | 0.0001 | 0.0001 | 0.0002 | 0.0004 |

### Visibility Impacts on Class I Areas – Downeast LNG Terminal

Table 4.11.1.5.5-8 shows the visibility impacts on nearby Class I areas for comparison with visibility impact threshold levels (Delta-E $\leq 2$ and Spectral, Green Wavelength Contrast Level $\leq 0.05$). All predicted visibility values are below the acceptable threshold levels and would not be a significant impact on visibility at Class I areas and St. Croix Island.

TABLE 4.11.1.5.5-8

**Visibility Impacts at Nearby Class I Areas Attributable to Downeast LNG Terminal Operations and Associated Vessel Activities**

| Sensitive Area | Delta-E from LNG Terminal Stationary Emissions (%) | Delta-E from Maritime Transit Emissions (%) | Spectral, Green Wavelength Contrast Level from LNG Terminal Stationary Emissions (%) | Spectral, Green Wavelength Contrast Level from Maritime Transit Emissions (%) |
|---|---|---|---|---|
| MWABU | 0.419 | 0.178 | -0.002 | -0.001 |
| MWAEU | 0.224 | 0.155 | 0.001 | 0.001 |
| RCIP | 0.519 | 0.504 | -0.003 | 0.002 |
| St. Croix Island | 0.946 | 0.509 | -0.004 | 0.002 |

### Compliance with Ambient Air Quality Standards – All Regional Sources

Table 4.11.1.5.5-9 shows the maximum predicted air quality impacts based on emissions from all potential regional sources including Downeast LNG, the previously proposed Calais LNG project, and Domtar. As shown, the maximum impacts would violate the one hour standards for $NO_2$ and $SO_2$; however, the air impact analysis reveals that 93 percent of the one hour $NO_2$ impact and more than 99 percent of the $SO_2$ impacts are attributable to emissions from other regional sources (not Downeast LNG).

TABLE 4.11.1.5.5-9

**Maximum Air Quality Impacts Based on Emissions from All Regional Sources (Downeast LNG, Calais LNG, Domtar)**

| Pollutant | Average | Background Concentration (μg/m$^3$) | Maximum Impact (μg/m$^3$) | Background + Impact (μg/m$^3$) | MAAQS/NAAQS (μg/m$^3$) | Exceedance |
|---|---|---|---|---|---|---|
| CO | 1-Hour | 4,568 | 1,603 | 6171 | 40,000 | No |
| CO | 8-Hour | 2,284 | 362 | 2646 | 10,000 | No |

TABLE 4.11.1.5.5-9

**Maximum Air Quality Impacts Based on Emissions from All Regional Sources (Downeast LNG, Calais LNG, Domtar)**

| Pollutant | Average | Background Concentration (μg/m$^3$) | Maximum Impact (μg/m$^3$) | Background + Impact (μg/m$^3$) | MAAQS/NAAQS (μg/m$^3$) | Exceedance |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-Hour | 47 | 1,199 | 1246 | 188 | **Yes** |
| $NO_2$ | Annual | 11 | 10.4 | 21 | 100 | No |
| $SO_2$ | 1-Hour | 33 | 778 | 811 | 195 | **Yes** |
| $SO_2$ | 3-Hour | 24 | 383 | 407 | 1,150 | No |
| $SO_2$ | 24-Hour | 13 | 52 | 65 | 230 | No |
| $SO_2$ | Annual | 5 | 2.2 | 7 | 57 | No |
| $PM_{10}$ | 24-Hour | 42 | 10.8 | 53 | 150 | No |
| $PM_{10}$ | Annual | 10 | 0.8 | 11 | 40 | No |
| $PM_{2.5}$ | 24-Hour | 18.6 | 10.8 | 29 | 35 | No |
| $PM_{2.5}$ | Annual | 5.7 | 0.8 | 7 | 15 | No |

Table 4.11.1.5.5-10 through table 4.11.1.5.5-13 show the maximum predicted air quality impacts on the four nearby Class I areas based on emissions from all regional sources (Downeast LNG, previously proposed Calais LNG, and Domtar). The combined emissions from these sources would not cause or contribute to a violation of an air quality standard at any nearby Class I area.

TABLE 4.11.1.5.5-10

**Maximum Air Quality Impacts at the MWABU Based on Emissions from All Regional Sources (Downeast LNG, Calais LNG, Domtar)**

| Pollutant | Average | Background Concentration (μg/m$^3$) | Maximum Impact (μg/m$^3$) | Background + Impact (μg/m$^3$) | MAAQS/NAAQS (μg/m$^3$) | Exceedance |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-Hour | 47 | 64.8 | 111.8 | 188 | No |
| $NO_2$ | Annual | 11 | 0.4 | 11.4 | 100 | No |
| $SO_2$ | 1-Hour | 33 | 45.2 | 78.2 | 195 | No |
| $SO_2$ | 3-Hour | 24 | 26.8 | 50.8 | 1,150 | No |
| $SO_2$ | 24-Hour | 13 | 7.7 | 20.7 | 230 | No |
| $SO_2$ | Annual | 5 | 0.7 | 5.7 | 57 | No |
| $PM_{10}$ | 24-Hour | 42 | 1.8 | 43.8 | 150 | No |
| $PM_{10}$ | Annual | 10 | 0.2 | 10.2 | 40 | No |
| $PM_{2.5}$ | 24-Hour | 18.6 | 1.8 | 20.4 | 35 | No |
| $PM_{2.5}$ | Annual | 5.7 | 0.2 | 5.9 | 15 | No |

Note: As shown in table 4.11.1.5.5-9, the maximum air quality impacts from CO for all regional sources are below the MAAQS/NAAQS; therefore, CO impacts at MWABU are not shown in this table.

TABLE 4.11.1.5.5-11

**Maximum Air Quality Impacts at the MWAEU Based on Emissions from All Regional Sources (Downeast LNG, Calais LNG, Domtar)**

| Pollutant | Average | Background Concentration ($\mu g/m^3$) | Maximum Impact ($\mu g/m^3$) | Background + Impact ($\mu g/m^3$) | MAAQS/NAAQS ($\mu g/m^3$) | Exceedance |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-Hour | 47 | 16.4 | 63.4 | 188 | No |
| $NO_2$ | Annual | 11 | 0.1 | 11.1 | 100 | No |
| $SO_2$ | 1-Hour | 33 | 9.2 | 42.2 | 195 | No |
| $SO_2$ | 3-Hour | 24 | 6 | 30 | 1,150 | No |
| $SO_2$ | 24-Hour | 13 | 1.6 | 14.6 | 230 | No |
| $SO_2$ | Annual | 5 | 0.2 | 5.2 | 57 | No |
| $PM_{10}$ | 24-Hour | 42 | 0.5 | 42.5 | 150 | No |
| $PM_{10}$ | Annual | 10 | 0.05 | 10 | 40 | No |
| $PM_{2.5}$ | 24-Hour | 18.6 | 0.5 | 19.1 | 35 | No |
| $PM_{2.5}$ | Annual | 5.7 | 0.05 | 5.7 | 15 | No |

Note: As shown in table 4.11.1.5.5-9, the maximum air quality impacts from CO for all regional sources are below the MAAQS/NAAQS; therefore, CO impacts at MWAEU are not shown in this table.

TABLE 4.11.1.5.5-12

**Maximum Air Quality Impacts at the RCIP Based on Emissions from All Regional Sources (Downeast LNG, Calais LNG, Domtar)**

| Pollutant | Average | Background Concentration ($\mu g/m^3$) | Maximum Impact ($\mu g/m^3$) | Background + Impact ($\mu g/m^3$) | MAAQS/NAAQS ($\mu g/m^3$) | Exceedance |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-Hour | 47 | 38.8 | 85.8 | 188 | No |
| $NO_2$ | Annual | 11 | 0.2 | 11.2 | 100 | No |
| $SO_2$ | 1-Hour | 33 | 12.3 | 45.3 | 195 | No |
| $SO_2$ | 3-Hour | 24 | 7 | 31 | 1,150 | No |
| $SO_2$ | 24-Hour | 13 | 1.3 | 14.3 | 230 | No |
| $SO_2$ | Annual | 5 | 0.2 | 5.2 | 57 | No |
| $PM_{10}$ | 24-Hour | 42 | 0.4 | 42.4 | 150 | No |
| $PM_{10}$ | Annual | 10 | 0.04 | 10 | 40 | No |
| $PM_{2.5}$ | 24-Hour | 18.6 | 0.4 | 19 | 35 | No |
| $PM_{2.5}$ | Annual | 5.7 | 0.04 | 5.7 | 15 | No |

Note: As shown in table 4.11.1.5.5-9, the maximum air quality impacts from CO for all regional sources are below the MAAQS/NAAQS; therefore, CO impacts at RCIP are not shown in this table.

TABLE 4.11.1.5.5-13

**Maximum Air Quality Impacts at the St. Croix Island Based on Emissions from All Regional Sources (Downeast LNG, Calais LNG, Domtar)**

| Pollutant | Average | Background Concentration ($\mu g/m^3$) | Maximum Impact ($\mu g/m^3$) | Background + Impact ($\mu g/m^3$) | MAAQS/NAAQS ($\mu g/m^3$) | Exceedance |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-Hour | 47 | 117.5 | 164.5 | 188 | No |
| $NO_2$ | Annual | 11 | 1.1 | 12.1 | 100 | No |
| $SO_2$ | 1-Hour | 33 | 41.5 | 74.5 | 195 | No |
| $SO_2$ | 3-Hour | 24 | 25 | 49 | 1,150 | No |
| $SO_2$ | 24-Hour | 13 | 5.1 | 18.1 | 230 | No |
| $SO_2$ | Annual | 5 | 0.4 | 5.4 | 57 | No |
| $PM_{10}$ | 24-Hour | 42 | 0.8 | 42.8 | 150 | No |
| $PM_{10}$ | Annual | 10 | 0.1 | 10.1 | 40 | No |
| $PM_{2.5}$ | 24-Hour | 18.6 | 0.8 | 19.4 | 35 | No |
| $PM_{2.5}$ | Annual | 5.7 | 0.1 | 5.8 | 15 | No |

Note: As shown in table 4.11.1.5.5-9, the maximum air quality impacts from CO for all regional sources are below the MAAQS/NAAQS; therefore, CO impacts at St. Croix Island are not shown in this table.

### Impacts from Nitrogen and Sulfur Deposition on Class I Areas – All Regional Sources

Table 4.11.1.5.5-14 shows the predicted cumulative nitrogen and sulfur deposition levels at nearby Class I areas for comparison with DATs. All predicted deposition rates exceed the DATs. However, the evaluation also reveals that emissions attributable to Calais LNG alone would yield a sulfur DAT exceedance at St. Croix Island and a nitrogen DAT exceedance at all four nearby Class I areas. Emissions from the Domtar pulp mill also contribute to or exceed the DATs at some of the areas. The nitrogen deposition rate at St. Croix Island attributable to Downeast LNG is more than an order of magnitude below the cumulative nitrogen deposition impact. As these Class I areas and St. Croix Island would have an impact in excess of the DATs there may be an impact on these Class I areas. St. Croix Island is a national historic site without significant wilderness habitat. It is unlikely that deposition should have a significant effect on AQRVs for the island. Impacts on the MWABU, MWAEU, and RCIP would be larger and may contribute to an adverse impact on AQRVs for the Class I areas.

TABLE 4.11.1.5.5-14

**Deposition Impacts at Nearby Class I Areas Based on Emissions from All Regional Sources (Downeast LNG, Calais LNG, Domtar)**

| Parameter | DAT (kg/ha/yr) | MWABU (kg/ha/yr) | MWAEU (kg/ha/yr) | RCIP (kg/ha/yr) | St. Croix Island (kg/ha/yr) |
|---|---|---|---|---|---|
| Nitrogen Deposition | 0.010 | 2.081 | 0.234 | 0.229 | 1.035 |
| Sulfur Deposition | 0.010 | 0.472 | 0.051 | 0.075 | 0.753 |

### Visibility Impacts on Class I Areas – All Regional Sources

To illustrate the impact of other sources in the region, table 4.11.1.5.5-15 shows the visibility impacts at nearby Class I areas based strictly on emissions from Calais LNG. Delta-E visibility thresholds are exceeded for each nearby Class I Area. Similarly, table 4.11.1.5.5-16 shows the visibility impacts at nearby Class I areas based strictly on emissions from the Domtar facility. All of the Delta-E visibility thresholds and spectral contrast thresholds are exceeded for each nearby Class I Area.

TABLE 4.11.1.5.5-15

**Visibility Impacts at Nearby Class I Areas Attributable to Calais LNG Terminal Operations and Associated Vessel Activities**

| Sensitive Area | Delta-E from LNG Terminal Stationary Emissions (%) | Delta-E from Maritime Transit Emissions (%) | Spectral, Green Wavelength Contrast Level from LNG Terminal Stationary Emissions (%) | Spectral, Green Wavelength Contrast Level from Maritime Transit Emissions (%) |
|---|---|---|---|---|
| MWABU | **6.6** | **2.50** | -0.029 | -0.011 |
| MWAEU | **2.7** | 0.74 | -0.012 | -0.003 |
| RCIP | **2.8** | **5.54** | -0.013 | -0.025 |
| St. Croix Island | **7.3** | **18.95** | -0.019 | 0.020 |

TABLE 4.11.1.5.5-16

**Visibility Impacts at Nearby Class I Areas Attributable to Domtar Operations**

| Sensitive Area | Delta-E (%) | Spectral, Green Wavelength Contrast Level (%) |
|---|---|---|
| MWABU | 31.8 | 0.248 |
| MWAEU | 7.8 | 0.061 |
| RCIP | 5.9 | 0.05 |
| St. Croix Island | 13.7 | 0.087 |

Based on the relative geographic locations of regional sources, only MWAEU and RCIP would potentially be affected by plume overlap from stationary sources or vessel transit activities. As shown in table 4.11.1.5.5-17, the cumulative impacts would exceed the Delta-E threshold for each of these Class I areas. However, at MWAEU, the Downeast vessel transit activities and Downeast LNG terminal operations represent only 11 percent and 8 percent of the cumulative Delta-E. At RCIP, the Downeast vessel transit activities represent about one-fourth of the cumulative Delta-E impact.

TABLE 4.11.1.5.5-17

**Cumulative Visibility Impacts at MWAEU and RCIP**

| Sensitive Area | Delta-E (%) | Spectral, Green Wavelength Contrast Level (%) |
|---|---|---|
| MWAEU | **3.1** | -0.014 |
| RCIP | **7.2** | 0.061 |

Although not the primary cause, the Downeast LNG terminal may contribute to a significant adverse visibility impact on the Class I areas and St. Croix Island.

**Impacts on the Canadian Province of New Brunswick**

Downeast modeled air quality impacts in the near field and on nearby Class I areas for comparison with National and Maine AAQS. The nearest Canadian land is just across the bay in the town of St. Andrews in New Brunswick. Air quality impacts for this area were not specifically modeled; however, based on the near field impacts described above, pollutant concentrations attributable to the Downeast LNG Project would be well within the Canadian National Ambient Air Quality Objectives.

**Engineering Controls for Methane Emissions and the Energy STAR Program**

The composition of natural gas typically includes between 90 and 95 percent methane. As a part of operations at the proposed facilities, small quantities of methane (a greenhouse gas) could be released to the atmosphere. Some methane would be intentionally vented to maintain equipment safety under abnormal operational conditions, and some would be released through unintentional leaks. Various engineering design features would be applied to minimize the potential for unintentional methane emissions from the LNG storage tanks, marine facilities, and sendout pipeline.

In an effort to mitigate methane emissions from oil and natural gas operations, the EPA established the Natural Gas STAR program. This program is a flexible, voluntary partnership that encourages oil and natural gas companies — both domestically and abroad — to adopt proven, cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. The program provides a framework to encourage partner companies to implement methane emission reduction technologies and practices and to document their voluntary emission reduction activities. Downeast has agreed to join the Natural Gas STAR program, and has appointed a Natural Gas STAR Program Implementation Manager responsible for the implementation of this voluntary agreement.

In summary, the engineering design of the Downeast LNG terminal would minimize fugitive methane emissions. In addition, although the terminal design includes a natural gas vent stack, there is no normal mode of operation in which it would be used (i.e. methane would only be vented during abnormal or emergency events).

Thus through implementation of construction work practices, the limited duration of construction activities, a review of the estimated emissions from construction and operations, and an analysis of the modeled air quality impacts from operation of the Downeast LNG terminal, ship emissions and other facilities, we do not believe there would be regionally significant impacts on air quality from construction and operation of the facility.

Potential impact of the project on global GHG emissions is discussed in section 4.13 of this EIS.

### 4.11.2 Noise

#### 4.11.2.1 Background and Noise Standards

Noise would affect the local environment during both the construction and operation of the proposed Downeast LNG terminal. At any location, both the magnitude and frequency of environmental noise may vary considerably over the course of the day and throughout the week. This variation is caused in part by changing weather conditions and the effects of seasonal vegetative cover. Two measures used by federal agencies to relate the time-varying quality of environmental noise to its known effect on people are the 24-hour equivalent sound level ($L_{eq(24)}$) and the day-night sound level ($L_{dn}$). The $L_{eq(24)}$ is the level of steady sound averaged over a 24-hour period. The $L_{dn}$ is the $L_{eq(24)}$ with 10 decibels on the A-weighted scale (dBA) added to the nighttime sound levels between the hours of 10 p.m. and 7 a.m. to account for the greater sensitivity of people to sound during the nighttime hours. For a perspective on how noise is perceived by a human listener, a 3 dBA increase is the threshold of the human perceptibility, a 6 dBA increase is clearly noticeable, and a 10 dBA increase is perceived as a doubling of noise, a significant increase to a human listener.

In 1974, the EPA published *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety* (EPA 1974). This publication evaluates the effects of environmental noise with respect to health and safety. The document provides information for state and local governments to use in developing their own ambient noise standards. The EPA has determined that in order to protect the public from activity interference and annoyance outdoors in residential areas, noise levels should not exceed an $L_{dn}$ of 55 dBA.

The FERC has adopted this criterion for new compression and associated pipeline facilities (18 CFR 380.12), and it is used here to evaluate the potential noise impact from operation of the Downeast LNG terminal. An $L_{dn}$ of 55 dBA is equivalent to a continuous noise level of 48.6 dBA for facilities that operate at a constant level of noise. Our guidelines also require that new pipeline facilities not result in a perceptible increase in vibration at any noise sensitive area (NSA). In addition, a sound level of 55 dBA ($L_{dn}$) can be used as a "benchmark noise criterion" for assessing the noise impact of temporary or intermittent noise. In addition to noise requirements, the Commission requires that LNG import or export terminal operations not result in any perceptible increase in vibration.

The Maine DEP Site Location of Development Regulation Chapter 375.10, Control of Noise, establishes quantitative noise limits for new projects in Maine such as the Downeast LNG Project (Maine DEP 2006b). Under this regulation, hourly sound level limits apply at facility property boundaries and at nearby "protected locations." Protected locations are defined as "any location accessible by foot, on a parcel of land containing a residence or approved subdivision..". Protected locations also include schools, state parks, and designated wilderness areas.

The Maine DEP exempts daytime construction noise that occurs between the hours of 7 a.m. and 7 p.m. or daylight hours, whichever is longer. However, nighttime construction must comply with the same nighttime sound level limits as routine operation.

Maine DEP Chapter 375.10, Section B.1 requires consideration of local quantifiable noise standards. Under this provision, when a development is located in a municipality that has a quantifiable noise standard, then the Maine DEP is to apply the local noise standard rather than the Maine DEP standard. Further, when noise produced by a facility is received in another municipality, the quantifiable noise standards of the other municipality must be taken into consideration.

Maine DEP noise standards are based on existing ambient sound levels and can be more stringent than the FERC requirements. In addition, state noise limits for nighttime periods are usually more stringent than daytime limits. The project would operate continuously for 24 hours per day. Consequently, to the extent the state limits apply, noise from the LNG project would generally be limited by noise standards applicable during nighttime hours.

The Town of Robbinston Land Use and Development Code (Amended March 1995) contains a noise standard for Conditional Uses (Section 12) Paragraph B.vi. The Robbinston noise standard provides only qualitative criteria for noise. The intent of these criteria is consistent with both the FERC and Maine DEP noise limits to protect surrounding noise sensitive land uses from adverse noise impact. Consequently, by complying with the FERC and Maine DEP noise regulations, the project would meet the intent of the noise control standard established by the Town of Robbinston, Maine. A summary of applicable noise standards are presented in table 4.11.2.1-1.

TABLE 4.11.2.1-1

**Summary of Applicable Sound Requirements by Agency, Criterion, and Associated Metric**

| **Agency** | **Criterion (dBA)** | **Metric ($L_{eq}$)** | **Measurement Location / Condition** |
|---|---|---|---|
| FERC | 55 | 24-hour $L_{dn}$ | Nearby NSA |
| | 48.6 | Hourly | Nearby NSA |
| Maine DEP | 75 | Hourly | Facility Property Line |
| | 60 a/ | Daytime Hourly | Protected Location a/ |
| | 50 a/ | Nighttime Hourly | Protected Location a/ |
| | 55 a/ | Daytime Hourly | Protected Location with low ambient levels |
| | 45 a/ | Nighttime Hourly | Protected Location with low ambient levels |
| Town of Robbinston | Not applicable | Qualitative | Comply with federal and state requirements |

a/ The nighttime limits at protected locations apply within 500 feet of sleeping quarters. At distances greater than 500 feet, or where no sleeping quarters exist (e.g., school), daytime limits apply during all operating hours.
NSA – Noise sensitive area.

### 4.11.2.2 Waterway for LNG Marine Traffic

The transit to the proposed LNG terminal passes Campobello Island, Indian Island, Deer Island, a number of smaller islands, and the Maine Coast with open water ranging from less than 1.0 mile in width to over 2.0 miles wide. Much of the shoreline is comprised of wooded hillsides and rocky shores meeting the water's edge. Concentrated development occurs in a few locations such as Eastport, Maine, and St. Andrews, New Brunswick. Additional seasonal and year-round residential development is found at scattered locations along the length of the transit route.

Ambient noise sources in the vicinity of the marine transit route include natural sounds from wind, waves, water currents and flow, marine species and other animals. Man-made underwater noise sources include cargo ships such as those traveling to the Bayside terminal facility north of the site, commercial fishing boats, and recreational boats.

No construction activity would occur along the marine transit route; therefore, there would be no impacts during the construction phase with the exception of any construction deliveries via barge. During project operation, noise would be produced from the operation of LNG vessels during transit to the LNG terminal site. Equipment onboard the LNG vessel includes boilers, steam-driven turbines, compressors, pumps, ventilation fans, and hydraulic systems. Of these, the ventilation fans are the predominant noise source as the majority of all the other equipment is contained within the double-hull vessel, which significantly attenuates the transmission of noise.

Noise generated by LNG vessel traffic along the waterway from the territorial sea to the proposed LNG terminal would be similar to noise from other large ships currently using the waterway. Downeast prepared a noise assessment for four of the closest points to land along the route to verify that the day/night level would not exceed 55 dBA. Assumptions used in this assessment included: (1) a vessel speed of 5 knots to provide a worst-case assessment in terms of duration of the noise at any point; (2) four accompanying tugs at half power with a noise level of 79 dBA at 50 feet; and (3) a vessel noise level similar to the tugs. A 30-minute and 1-hour $L_{eq}$ level was then computed for every 500-foot segment of shoreline on both the United States and Canadian sides of the route. Day/night levels were then computed assuming that the transit first occurred during the day and again if the transit occurred at night. The results of this analysis are presented in table 4.11.2.2-1. The highest day/night level of 51 dBA was predicted for a nighttime transit past the east shore of Moose Island at a close-in distance of 600 feet.

TABLE 4.11.2.2-1

**Sound Level Estimates During LNG Vessel Transit**

| Shoreline Location | Distance from Transit Route | Transit Operation | Combined Sound Level (dBA) During Transit Pass-By | | | |
|---|---|---|---|---|---|---|
| | | | 30-Minute | Hourly $LA_{eq}$ | Day-Night $L_{dn}$ | |
| | | | | | Day Event | Night Event |
| East Shore of Moose Island | 600 ft | LNG Vessel & Tugs | 58 | 55 | 41 | 51 |
| Kendall Head | 1,300 ft | LNG Vessel & Tugs | 54 | 51 | 37 | 47 |
| South Shore of Deer Island | 1,300 ft | LNG Vessel & Tugs | 54 | 51 | 37 | 47 |
| North End of Grand Manaan Island | 1,300 ft | LNG Vessel Only | 47 | 44 | 30 | 40 |

Note: Except for transit off the north end of Grand Manaan Island, assumes transit speed of 5 knots with one LNG vessel escorted by up to four tugboats.

In the marine environment, increased vessel traffic from the other marine projects in the area would result in increased ambient background underwater noise. These cumulative noise levels could cause auditory trauma, temporary or permanent loss of hearing sensitivity, habitat exclusion, habituation, and disruption of other normal behavior patterns, such as feeding, migration, and communication, to marine mammals and sea turtles. However, noise associated with the normal operation of additional vessels along the waterway would likely cause an insignificant incremental increase in noise impacts. See further discussion of underwater noise during project operation in section 4.11.2.3.3.

### 4.11.2.3 LNG Terminal

#### 4.11.2.3.1 Ambient Noise

Sound levels in the vicinity of the proposed LNG terminal were monitored for a minimum 24-hour period to determine existing ambient sound levels at six NSAs and protected locations in the vicinity of the project site (figure 4.11-1). A summary of ambient monitoring results are presented in this section.

The primary surrounding land use is rural residential intermixed with undeveloped wooded land and commercial or public land uses. Several residential properties are located to the south and west of the site, generally along U.S. Route 1. The nearest residences to the proposed LNG terminal are along U.S. Route 1 across from the project site. To the south, there are a few residences 1,500 feet or more from U.S. Route 1 moving toward the shoreline. These residences are over 2,000 feet from the project site. To the northwest, there is a cluster of residential properties along Ridge Road near the intersection of U.S. Route 1. There is also a local utility station and small retail store in this area. North of the site, several residential properties, a church, elementary school, and fire station are located along U.S. Route 1. There are also several waterfront homes on Passamaquoddy Bay northeast of the site.

Existing pre-development sound level readings taken for the Robbinston site are summarized in table 4.11.2.3-1. Calculated values are the FERC daytime $L_{eq}$ (7 a.m. to 10 p.m.), nighttime $L_{eq}$ (10 p.m. to 7 a.m.), and $L_{dn}$. The $L_{dn}$ levels ranged from 39 dBA at monitoring position MP-6 to 57 dBA at monitoring positions MP-3 and MP-4. The $L_{eq}$ represents the average energy level of all sounds present during the measurement period. The one-hour $L_{eq}$ is the parameter specified for use by the Maine DEP for establishing pre-development ambient sound levels.

TABLE 4.11.2.3-1

**Existing Sound Levels and Noise Limits**

| Monitoring Position | Existing Day-Night Sound Level ($L_{dn}$): At Monitoring Position | Existing Day-Night Sound Level ($L_{dn}$): At Nearby NSAs a/ | Average Nighttime $L_{eq}$ (7 pm to 7 am) a/ | Sound Level Limits (dBA): FERC $L_{dn}$ | Sound Level Limits (dBA): Maine DEP Nighttime b/ |
|---|---|---|---|---|---|
| MP-1 | 44 | 44 | 32 | 55 dBA at NSA ($L_{eq}$ = 48.6) | 45 |
| MP-2 | 48 | 44 to 57 | 41 | | 50 |
| MP-3 | 57 | 50 to 57 | 44 | | 50 |
| MP-4 | 57 | 48 to 59 | 47 | | 50 |
| MP-5 | 52 | 48 to 59 | 42 | | 50 |
| MP-6 | 39 | 39 | 31 | | 45 |

a/ Based on distance from primary traffic noise source (U.S. Route 1 or Ridge Road).
b/ Nighttime limits at a protected location apply within 500 feet of a residence.

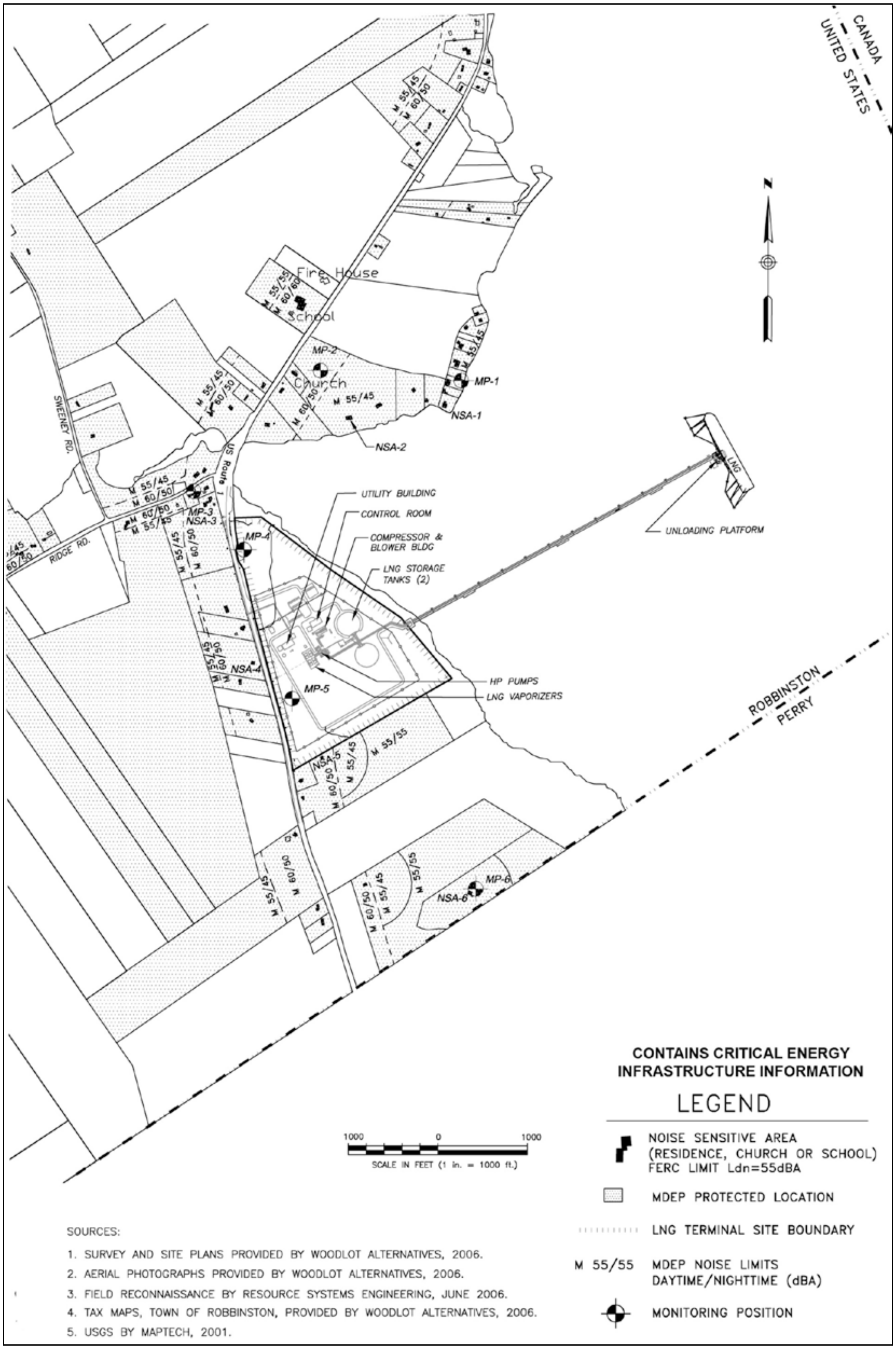


**Figure 4.11-1**
**Downeast LNG Project**
**Vicinity Site Map**

#### 4.11.2.3.2 LNG Terminal Construction Noise Impacts

The proposed LNG terminal would consist of land-based and marine-based facilities that would be constructed in parallel. Activities during construction would have the potential to cause noise impacts on the surrounding area. Noise associated with most construction equipment would be intermittent and all major construction activity would be limited to daytime or daylight hours.

**Marine-Based Facilities**

Construction of the pier is expected to be done on an 8 to 12 hours per day (daylight hours) basis and last for approximately 16 months. The major marine work would include the following key activities: pile construction, dolphin construction, and decking construction. Powered mechanical equipment, including marine crafts, and pile-driving hammers may be the principal sources of noise during the construction phase of the marine work. Most diesel powered construction equipment produces a sound level of 80 to 85 dBA at 50 feet in air. Tugboat levels can be as high as 90 dBA in air. During impact type pile driving, the maximum sound levels (in air) upon impact range from 105 to 115 dBA at 50 feet.

Large diameter steel pipe piles are anticipated to be used to support the trestle and loading platform. These piles would be vibrated and driven through any surficial soils on the seabed to the top of the underlying rock where they would be seated into competent bedrock. The use of a vibratory hammer to drive piles, rather than an impact hammer, would reduce noise impacts on the surrounding area. In a filing with the Commission on May 3, 2013 Downeast stated that on the basis of its current design and engineering, vibratory hammering would be used exclusively for pile driving, and committed to using only vibratory hammering for pile driving.

<u>Underwater Noise</u>

Underwater noise from construction of the project may have the potential to affect marine mammals in Passamaquoddy Bay. This section describes some of the basic acoustics associated with underwater noise along with guidelines of the NOAA Fisheries designed to protect marine mammals from "acoustic harassment." This discussion complements the discussion found in the aquatic resources section on marine mammals (section 4.5.2) and endangered and threatened species (section 4.6). The hearing capabilities and frequency responses of marine mammals and aquatic life vary significantly. The dBA scale for in air sound, which was designed specifically for the human ear frequency response, is inappropriate in the analysis of underwater sound.

NOAA Fisheries has established interim guidelines for what constitutes harassment and acoustic takes on marine mammals under the MMPA and the ESA as a result of exposure to anthropogenic noise in the marine environment. Two levels of acoustic harassment have been defined in the MMPA. The current thresholds are 180 dB re 1 μPa for Level A harassment and 160 dB re 1 μPa (impulse) and 120 decibels (dB) re 1 microPascal (μPa) (continuous) for Level B harassment. Exceedance of these thresholds may result in adverse impacts on marine mammals. These criteria are currently undergoing review and are subject to change.

Underwater noise during construction activities could result in temporary behavioral changes of birds, fish, and ocean mammals in the immediate area of the active construction. However, due to the temporary nature of construction activity, long-term noise impacts are not expected to be significant.

The loudness of underwater sound is dependent on the radiated sound power of the source and the propagation and attenuation characteristics of the medium through which the sound passes (sea water). Similar to in-air sound, the standard unit of measure for underwater sound is the decibel. Because of the different physical properties of air and water, identical sound pressure waves in-air and underwater would have different values in the two fluids. Thus, no attempt should be made to equate decibel levels reported for water with those in-air, or vice-versa. Underwater noise impacts are identified in dB relative to the reference sound pressure level of 1 μPa while in air, decibels are assumed to use the reference sound pressure level of 20 μPa.

Downeast has filed sound contour maps of the underwater noise impacts along the vessel corridor and during terminal construction (see figures 8 through 12 in Appendix Q). The report includes estimates of source data terms and an explanation of the acoustic engineering methodology used for the calculation of underwater sound propagation and resultant contours. Noise contours are provided in Appendix Q. The results of this study are summarized below.

Modeling was completed with a proprietary acoustic model that is used to predict the directional transmission loss of a single or multiple sources.

All data are reported as root mean square (RMS) sound pressure level upon which NOAA Fisheries safety radius requirements are based, except for underwater noise generated during pile driving, which are reported as both a one second sound exposure level and RMS to properly account for this noise source, similar but not exactly the same as the maximum A-weighted sound pressure level ($LA_{max}$). Results are also summarized in tables in terms of the 95 percent radius to received level, including thresholds relevant to NOAA Fisheries criteria for Level A and Level B harassment. The 95 percent radius is defined as the radius of a circle that encompasses 95 percent of the points whose value is equal to or greater than the threshold value (meaning that 95 percent of the time the noise within that radius will be equal to or below the identified noise level).

The marine construction activity at the Downeast LNG terminal that would produce underwater noise would be primarily from tugboats, operation of barge-mounted equipment, and pile driving (vibratory hammering). Neither dredging nor offshore drilling are anticipated at the Downeast LNG Project, and as such, has not been evaluated relative to noise impacts. With the exception of mooring dolphins, pier construction would use "over the top" method that limits the use of tugs and work barges. However, in deeper waters, construction may require the use of tugs and barges and these were assumed to ensure worst-case conservative results.

The sound generated by construction vessels would be proportionate to vessel size, speed, engine load, and revolutions per minute with broadband source levels driven primarily by propeller cavitations, hydrodynamic flow over the hull and hull appendages, and operation of machinery onboard. Broadband linear source values were estimated at 185 dB re 1 μPa for a tug movement at half speed and 193 dB re 1 μPa for a tug with engines at full load as would occur during pushing or pulling operations. Broadband barge source levels were estimated at 175 dB re 1 μPa. Source levels were based on field measurements of tug and barge operations during construction of a similar project.

Aside from tug operations, the primary sources of underwater noise during construction of the LNG terminal would be the installation of the steel pilings. In a filing with the Commission on

May 3, 2013 Downeast stated that on the basis of its current design and engineering, vibratory hammering would be used exclusively for pile driving, and committed to using only vibratory hammering for pile driving. Underwater noise generated during pile driving would be dependent on the length and diameter of the pile and the impact energy exerted by the hammer. The steel pilings used in construction of the pier would be 4 feet in diameter, with a wall thickness of 1 inch. Broadband source values used for the Downeast underwater noise modeling for vibratory pile driving was 199 dB re 1 μPa, with a source depth of 7 meters at the terminal and 3 meters mid-trestle. In reality, sound would radiate from all areas of the pilings. The mid-trestle value is a conservative estimate of the depth for an equivalent point source, as losses would be less for a source at mid-trestle than one close to the sea floor. The radii for modeled construction scenarios are presented in table 4.11.2.3-2.

TABLE 4.11.2.3-2

**Radius of Underwater Noise Levels During Construction**

| Noise (dB a/) | Noise Source(s) | | | | | | |
|---|---|---|---|---|---|---|---|
| | Barge at the Terminal, Barge + Tug Mid-Trestle | Vibratory Hammer at the Terminal | | Vibratory Hammer + Barge Mid-Trestle | | Barge + Vibratory Hammer at the Terminal, Barge + Tug Mid-Trestle | |
| | | Unmitigated | Mitigated | Unmitigated | Mitigated | Unmitigated | Mitigated |
| 190 | 5 m | 5 m | -- | 5 m | -- | 5 m | < 5 m |
| 180 b/ | 457 m | 11 m | < 5 m | 11 m | < 5 m | 455 m | 455 m |
| 170 | 470 m | 60 m | 14 m | 81 m | 14 m | 457 m | 457 m |
| 160 | 529 m | 394 m | 63 m | 376 m | 88 m | 522 m | 522 m |
| 150 c/ | 732 m | 1.86 km | 409 m | 2.4 km | 409 m | 1.93 km | 834 m |
| 140 | 1.59 km | 6.8 km | 1.92 km | 10.2 km | 2.46 km | 10.0 km | 1.92 km |
| 130 | 4.5 km | 11.7 km | 7.5 km | 11.0 km | 10.3 km | 11.7 km | 7.49 km |
| 120 d/ | 10.5 km | 16.0 km | 12.4 km | 11.3 km | 11.1 km | 16.0 km | 12.4 km |

a/ dB referenced to 1 μPa
b/ Level A Harassment
c/ Atlantic sturgeon criterion
d/ Level B Harassment

Example: for the vibratory hammer at the terminal, the maximum noise would be 190 dB re 1 μPa or below within 5 meters of the hammer, 180 dB between 5 meters and 11 meters, 170 dB between 11 meter and 60 meters, etc.

Radii corresponding to Level A and Level B harassment criteria are identified in table 4.11.2.3-2. This distance represents the minimum distance from a given source or activity to a received underwater sound level. For example, for the vibratory hammer at the terminal, the maximum noise would be 190 dB re 1 μPa or below within 5 meters of the hammer, 180 dB dB re 1 μPa between 5 meters and 11 meters, 170 dB re 1 μPa between 11 meters and 60 meters, etc. Received sound levels above the 180 decibels dB re 1 μPa on the unweighted scale (dBL) NOAA Fisheries criterion would occur during pile driving directly in the water column. Figures 14 through 17 of Appendix Q present estimated underwater received sound level contour maps resulting from unmitigated pile-driving activities.

In order to minimize underwater noise impacts, Downeast has also analyzed the use of a bubble curtain as mitigation, which has been shown to provide a mean 1/3 octave band attenuation in the 63-6300 Hz range of approximately 10 dB. The derived attenuation values of the bubble curtain were applied to the source levels of the vibratory pile driving. The broadband source level for vibratory pile driving was reduced from 199 dB re 1 μPa to 187 dB re 1 μPa using the bubble curtain. In construction areas where vibratory hammering is used, this reduction would allow for corridors of safe passage (where received levels are less than 150 dB re 1 μPa) for Atlantic sturgeon in the following areas:

- west of St. Andrews, NB;
- the St. Croix River;
- between St. Andrews and Deer Island, NB; and
- between Deer Island, NB and Eastport, ME.

In addition, as identified in section 4.6.2.2, Downeast has accepted several recommendations from NOAA Fisheries to mitigate noise impacts on aquatic species.

Figures 1 through 4 of Appendix Q Addendum present estimated underwater sound level contour maps resulting from mitigated pile-driving activities.

**Land-Based Facilities**

Each LNG storage tank would be built on a reinforced concrete slab foundation supported on un-weathered bedrock. Construction of the pier abutment and lower access road would require removal of 20 to 35 vertical feet of rock. Where removal of significant thickness of rock is required at the project site, controlled drilling and blasting techniques would be utilized. To the extent possible, rock would be processed and reused on-site such as to construct the shoreside rock barrier around the LNG storage tanks.

Construction of land-based facilities at the LNG terminal, including drilling and blasting, would normally occur during daylight hours or between the hours of 7 a.m. to 7 p.m. Construction is expected to last for a period of 35 to 36 months.

A variety of construction equipment would be used to construct the proposed facilities. This would include earth moving equipment for land clearing, excavation, and grading. Typical earth moving equipment, such as loaders, excavators, and bulldozers, generates a sound level of 75 to 88 dBA at a distance of 50 feet. Equipment used for drilling, hammering or excavation of rock have the potential to generate higher sound levels depending upon the specific type of equipment used. Areas where bedrock would be removed are located on the east side of the project site, which is considerably further away from the nearest NSAs and protected locations (refer to figure 4.11-1).

Sound level estimates at the NSAs for general construction of the terminal and for onshore pile driving are presented in table 4.11.2.3-3.

TABLE 4.11.2.3-3

**Sound Level Estimates for LNG Terminal Construction Activity**

| NSA | Distance/Direction from Compressor/Blower Building (feet) | Typical Construction Activity | | Pile Driving a/ | | |
|---|---|---|---|---|---|---|
| | | Hourly $L_{eq}$ | $L_{dn}$ b/ | $LA_{max}$ | Hourly $L_{eq}$ c/ | $L_{dn}$ b/ |
| 1 | NE at 2,850 | 47 | 44 | 75 | 65 | 62 |
| 2 | N at 2,300 | 47 | 44 | 72 | 62 | 59 |
| 3 | NW at 2,100 | 44 | 41 | 64 | 54 | 51 |
| 4 | WSW at 800 | 54 | 51 | 65 | 55 | 52 |
| 5 | S at 1,400 | 50 | 47 | 67 | 57 | 54 |
| 6 | SE at 3,300 | 42 | 39 | 64 | 54 | 51 |

a/ Estimates are for impact pile driving however Downeast has committed to using only vibratory pile driving which would result in sound levels below these estimates.

b/ Based on a construction period of 7 am to 7 pm.
c/ Based on impact noise occurring 10% of the period in one hour.

Noise from pile driving has the potential to exceed the FERC guideline of 55 $L_{dn}$ and Maine DEP hourly noise limits at some nearby locations. In addition, pile driving impacts have a $LA_{max}$, which is the measurement of instantaneous noise. Typical noise metrics, $L_{eq}$, $L_{dn}$, do not capture the maximum noise from instantaneous noise. As can be seen in table 4.11.2.3-3, the maximum instantaneous noise from pile driving would be from 64 to 75 dBA, which is slightly above the level of human speech and at the higher level (above 70 dBA) may have a mild effect on speech intelligibility. Sound level estimates shown in table 4.11.2.3-3 are for impact hammer pile driving. Downeast has now committed to using only vibratory pile driving, which would result in sound levels below those estimated for impact pile driving.

While the noise from standard onshore pile driving would result in high levels, or noise for an extended period of time could be significant, Downeast has commited to using a vibratory pile driver. This would reduce noise impacts below the level of interference with human speech intelligibility. Because of the temporary nature and moderate magnitude noise from pile driving, no adverse or long-term effects are anticipated. Noise from pile driving and other construction activity may be noticeable at nearby residences, especially during periods of extensive earthwork using heavy equipment. Local traffic during the construction phase is also expected to increase, along with associated vehicle noise.

The mobile nature of construction noise sources and the continuous manner in which construction work must be done makes complete control of construction noise infeasible. Downeast would perform major construction activity between the hours of 7 a.m. and 7 p.m., or daylight hours, and therefore, would be exempt from relevant state of Maine construction noise limits during these hours. Other measures to mitigate construction noise would include compliance with federal regulations limiting noise from trucks and portable compressors, and ensuring that equipment and sound muffling devices provided by the manufacturer are kept in good working condition.

#### 4.11.2.3.3 LNG Terminal Operation Noise Impacts

During operation of the LNG terminal, sound would be generated by watercraft during berthing and de-berthing of LNG vessels, and full operation of the terminal during unloading and vaporization of LNG. Section 2.0 of this EIS provides a detailed description of the equipment and operations.

**Marine-Based Facilities**

The primary noise sources at the offshore terminal are the LNG vessels and tugboats that would only be used during berthing and de-berthing of LNG vessels. Equipment onboard the LNG vessel includes boilers, steam-driven turbines, compressors, pumps, ventilation fans, and hydraulic systems. Of these, the ventilation fans are the only noticeable sources of noise since all the other equipment is contained within the double-hull vessel which greatly attenuates the noise. Salt water ballast tanks surround the engineering spaces and provide a significant level of attenuation of the engine noise into the water and air. Similar noise levels would be expected from diesel powered vessels because of these isolating tanks. The diesel powered tugs would operate at high power levels when pushing or pulling LNG vessels during berthing operations. Consequently, the highest sound levels would occur during the berthing process, which is expected to occur over a period of approximately 30 minutes. The estimated sound level from a single tug operating at full power is 89 dBA at 50 feet. The estimated sound levels at the NSAs during the berthing cycle, including four tugboats and one LNG vessel, are presented in table 4.11.2.3-4 and illustrated in figures 10 through 12 of Appendix Q. The noise level of the LNG vessel during unloading of LNG would be insignificant.

TABLE 4.11.2.3-4

**Sound Level Estimates During LNG Vessel Berthing**

| NSA | Distance/Direction from LNG Pier (feet) | Sound Level During Berthing (dBA) | | |
|---|---|---|---|---|
| | | 30-Minute Cycle | Hourly $L_{eq}$ | $L_{dn}$ |
| 1 | WNW at 3,100 | 48 | 45 | 31 |
| 2 | W at 4,100 | 45 | 42 | 28 |
| 3 | W at 5,850 | 37 | 34 | 20 |
| 4 | WSW at 5,700 | 42 | 39 | 25 |
| 5 | SW at 5,500 | 42 | 39 | 25 |
| 6 | SSW at 5,500 | 38 | 36 | 22 |

The sound level for the 30-minute cycle is based on tugs operating at full power for the entire 30-minute period. During the berthing cycle, there are likely to be intermittent periods of operations at less than full power. Although watercraft underway is exempt from Maine DEP sound limits, the estimated sound levels during the berthing cycle are at or below the nighttime limit of 45 dBA for protected locations in quiet areas.

<u>Operation Underwater Noise Impacts</u>

During terminal operation, underwater noise from the offshore marine facility would be produced primarily from the operation of LNG vessels and support vessels (tugboats) during transit, and docking/undocking activities. Ambient underwater noise sources in the vicinity of the LNG terminal site include natural sounds from wind, waves, water currents and flow, precipitation, and biological noise from marine mammals and other species. Man-made underwater noise sources include cargo ships such as those traveling to the Bayside terminal facility north of the site, commercial fishing boats and bottom trawlers, and recreational boats.

Underwater noise generated during facility operation would be principally due to the addition of LNG vessel traffic. Transit of LNG vessels to and from the terminal through the Bay of Fundy would occur along the designated shipping lanes. Downeast expects that transit through the Bay of Fundy would be unescorted, but shortly before entering Head Harbour Passage, a pilot and four tugs would join the vessel and would assist in docking/undocking operations. Downeast expects that three of the tugs would be active during docking/undocking activities, while one would remain on standby.

At typical cruising speeds, source sound levels emitted by LNG vessels are dominated by propeller cavitation; therefore, factors such as propeller diameter, propeller speed, and number of blades impacts the source sound level. The predicted noise for an LNG vessel cruising at half-speed is 175 dB re 1 μPa. Tugs used for docking/undocking activities would likely be powered by two main 3,300 hp diesel engines, equipped with an azimuthal propulsion system. Predicted noise for a similar tug operating at half-speed and at maximum load are 185 dB re 1 μPa and 193 dB re 1 μPa, respectively. Underwater noise associated with the pilot vessel would be expected to be negligible in comparison to that generated from the vessel and tugs.

Newer LNG vessels are equipped with bow and/or stern thrusters, which can have highly variable sound output. Not all LNG vessels have such thrusters and in most cases the vessel's thrusters would not operate at full power simultaneously with all three tugs at maximum load. Use of the LNG's vessel's thrusters alone or in combination with tug support is at the discretion of the vessel's captain, in consultation with the attending pilot, and is dependent on the weather and sea condition during the berthing of the LNG vessel. For the purposes of the model, three tugs operating at high power were included without the addition of the vessel's thrusters. For docking, the vessel was not included at all as its sound would be negligible compared to the tugs. Five separate sites were used in modeling project operations to represent the different transit routes and docking station potentially used by the LNG vessel and support vessels. Sites 1 and 2 model the vessel at half speed while in transit through the Bay of Fundy. Sites 3 and 4 model the vessel at half speed with four tugs at half speed as they approach Passamaquoddy Bay. Modeling Site 5 represents the docking/undocking scenario, which only includes three tugs at high power and one tug on standby at half speed. The 95th percentile radii for operational scenarios are presented in table 4.11.2.3-5. Radii corresponding to Level A and Level B harassment criteria are identified in the table. This table represents the worst-case seasonal and tidal conditions. This distance is the linear distance from a given activity at which exceedances may occur. For example, for Site 1 LNG Vessel, Transiting, the maximum noise is expected to be 160 dB re 1 μPa or below within 5 meters, 150 dB between 5 meters and 18 meters, 140 dB between 18 meters and 55 meters, etc. Received sound levels above the 180 dBL NOAA Fisheries criterion are not likely at any appreciable distance during facility operations.

TABLE 4.11.2.3-5

**Radius of Underwater Noise Levels During Operation**

| Noise (dB a/) | Noise Source(s) | | | | |
|---|---|---|---|---|---|
| | Site 1 LNG vessel, Transiting | Site 2 LNG Vessel, Transiting | Site 3 LNG Vessel + 4 Tugs, Transiting | Site 4 LNG Vessel + 4 Tugs, Transiting | Site 5 LNG Vessel + 4 Tugs, Docking |
| 190 | -- | -- | < 5 m | < 5 m | < 5 m |
| 180 b/ | -- | -- | < 5 m | < 5 m | 10 m |
| 170 | < 5 m | < 5 m | 14 m | 14 m | 38 m |
| 160 | 5 m | 5 m | 41 m | 42 m | 207 m |
| 150 | 18 m | 18 m | 225 m | 267 m | 700 m |
| 140 | 55 m | 53 m | 898 m | 814 m | 2.0 km |
| 130 | 312 m | 257 m | 2.9 km | 2.9 km | 4.8 km |
| 120 c/ | 1.03 km | 1.06 km | 9.8 km | 8.5 km | 10.4 km |

a/ dB referenced to 1 μPa
b/ Level A Harassment
c/ Level B Harassment

Example: for Site 1 LNG Vessel, Transiting, the maximum noise would be 160 dB re 1 μPa or below within 5 meters , 150 dB between 5 m and 18 m, 140 dB between 18m and 55 m, etc.

Sound contour maps showing estimated underwater received sound levels resulting from LNG vessels and tugs in transit and during docking/undocking are provided in figures 8 through 13 of Appendix Q. Figures 22 and 23 in Appendix Q show estimated underwater received sound levels during LNG vessel docking/undocking, accounting for seasonal and tidal variability.

**Land-Based Facilities**

This section provides estimates of the resulting sound levels at NSAs from operation of the LNG terminal. Predicted sound levels are based on full operation of the facility at the peak sendout rate during unloading of an LNG vessel and with the design noise mitigation measures installed. Noise from other routine operating modes is expected to be at or below these predicted sound levels.

Downeast’s site development plan incorporates several key design elements to mitigate environmental impacts such as noise. Primary equipment would be located inside buildings, and storage tanks or vessels would contain noise from many of the pumps. Similar noise mitigation measures have been installed at other LNG facilities in the United States where sound testing has demonstrated that these LNG terminals operate within applicable FERC noise limits.

Noise levels of LNG terminal equipment are based on equipment and material specifications, performance data, measurements of similar equipment at existing LNG facilities, and technical literature.

Sound level estimates of project operation at nearby NSAs and protected locations were calculated using the DataKustik CadnaA noise prediction model. Modeling assumptions consisted of minimal ground absorption and vertically elevated noise sources to reduce attenuation from intervening terrain and buildings or structures. Table 4.11.2.3-6 presents estimates of sound levels from the Downeast LNG terminal at nearby NSAs and protected locations. The distances found in table 4.11.2.3-6 are measured from the center of the compressor/blower building to the locations where noise limits apply based on the FERC and Maine DEP noise regulations. Distances to other noise sources such as those operating at the unloading platform may vary considerably (refer to figure 4.11-1). Because Maine DEP limits apply to the entire parcel containing a residence, distances to protected locations are typically less than distances to nearby NSAs where the FERC limits apply. The sound level estimates are compared to the FERC and Maine DEP noise limits and show that the LNG project would operate below those limits under full load conditions. Day/night sound levels from the terminal would range from 38 to 51 dBA at the NSAs.

TABLE 4.11.2.3-6

**Sound Level Estimates and Limit Comparison for Peak Sendout at 625 MMscfd**

**FERC Limit - $L_{dn}$ = 55 dBA at NSA**

| NSA | Direction and Distance (feet) a/ | Existing $L_{dn}$ at NSA | $L_{dn}$ from LNG Terminal | Future Ambient $L_{dn}$ | Increase in Ambient $L_{dn}$ |
|---|---|---|---|---|---|
| 1 | NE at 2,850 | 44 | 41 | 46 | 2 |
| 2 | N at 2,300 | 46 | 43 | 48 | 2 |
| 3 | NW at 2,100 | 55 | 44 | 55 | 0 |
| 4 | WSW at 800 | 52 | 51 | 55 | 3 |
| 5 | S at 1,400 | 46 | 46 | 49 | 3 |
| 6 | SE at 3,300 | 39 | 38 | 42 | 3 |

**Maine DEP Limits – Hourly $L_{eq}$ at Protected Locations**

| Protected Location | Direction and Distance (feet) b/ | Estimated Hourly $L_{eq}$ From LNG Terminal Operation | Maine DEP Sound Level Limits (dBA) Daytime | Maine DEP Sound Level Limits (dBA) Nighttime |
|---|---|---|---|---|
| 1 | NE at 2,800 | 35 | 55 | 45 |
| 2 | N at 2,200 | 37 | 55 | 45 |
| 3 | NW at 1,970 | 38 | 60 | 50 |
| 4 | WSW at 750 | 46 | 60 | 50 |
| 5 | S at 1,200 | 41 | 55 | 45 |
| 6 | SE at 3,300 | 33 | 55 | 55 |

a/ Distances are from center of compressor/blower building to nearby NSA as defined by FERC.
b/ Distances are from center of compressor/blower building to nearby protected location as defined by Maine DEP.

In addition to sound levels from the LNG project, table 4.11.2.3-6 also provides estimates of future ambient sound levels ($L_{dn}$) at nearby NSAs and the expected increase above existing ambient sound levels. As a result of operations at the LNG terminal, sound levels at nearby NSAs are expected to increase from 0 to 3 dBA.

Because the terminal operational noise levels discussed above are estimates, **we recommend that:**

- **Downeast should file a full load noise survey with the Secretary <u>no later than 60 days after placing the Downeast LNG terminal and meter station into service</u>. If a full load condition noise survey is not possible, Downeast should file an interim survey at the maximum possible load <u>within 60 days of placing the Downeast LNG terminal and meter station into service</u> and file the full load survey results with the**

**Secretary <u>within 6 months of the in-service date</u>. If the noise attributable to the operation of all the equipment of the Downeast LNG terminal and meter station at full operation exceeds 55 dBA $L_{dn}$ at any nearby NSAs, Downeast should install additional noise controls to meet the level <u>within 1 year of the in-service date</u>. Downeast should confirm compliance with this requirement by filing a second full load noise survey with the Secretary <u>no later than 60 days after it installs the additional noise controls</u>.**

A number of the scoping comments received by the Commission indicated stakeholder concern about noise from the proposed LNG terminal adversely affecting the existing quality of life of area residents. The analyses presented above indicate that adequate measures would be taken in all aspects of the project to ensure that the FERC and state of Maine noise standards would be met and that there would be no significant noise impact on any residence. Although noise from construction activities may be audible at times, they would occur primarily during the day and would be temporary in nature. Noise from facility operations would be ongoing but at a lower level than construction, and it would generally not be noticeable at most residences.

### 4.11.2.4 Sendout Pipeline

Land use along the proposed sendout pipeline right-of-way is primarily existing rights-of-way and rural, forested land. Ambient sound was not measured for this assessment, but for this type of land use could be generally described as sounds associated with wildlife (animals, birds, and insects). Other sounds likely found along the proposed route include occasional vehicles at road crossings, and in the winter, occasional sounds from recreational ATVs.

#### 4.11.2.4.1 Pipeline Construction Noise Impacts

Construction of the sendout pipeline is primarily land-based, but would also rely on special techniques for crossing waterbodies, roads, railroads, and utilities. Activities during the construction phase have the potential to cause noise impacts on the surrounding area. Noise associated with most construction equipment would be intermittent and all major construction activity would be limited to daytime or daylight hours.

Pipeline construction would proceed at 100 to 200 feet per day, limiting the duration of noise exposure at any single location. In addition, Downeast would require certain mitigation measures as follows:

- all construction equipment would be required to be properly maintained and have muffling equipment;
- hours of construction activities would generally be limited to normal daylight working hours; and
- equipment operations adjacent to residences would be restricted to those specifically required for the pipeline installation (i.e., restricted access for vehicular passage along the pipeline right-of-way).

<u>Horizontal Directional Drilling</u>

For construction of the sendout pipeline, Downeast is proposing to implement HDDs for installation of the pipeline at numerous locations. Using this technology would enable drilling or tunneling under certain environmental features to minimize disturbance to residences, waterbodies, wildlife habitat, and other sensitive areas. Figures R-1 through R-12 in Appendix R, are a series of aerial plans that identify the planned HDD locations in relation to surrounding land uses and NSAs. From entry to exit points, the length of the HDD crossings range from approximately 141 feet (HDD Site No. C-37-109-01) to 6,621 feet (1.26 miles) along the United States side of the St. Croix River (HDD Site No. C-24-03). The lengths of the HDD crossings vary by location as summarized in table 4.11.2.4-1 in relation to pipeline mileposts.

Equipment planned for use at the HDD sites also varies somewhat depending on the length and depth of each drill, and subsurface soil and bedrock conditions. For longer HDD crossings with deeper bedrock penetration, equipment would include a drill rig, hydraulic crane, mud pump, generators, a screening/filter system for drill cuttings, and mobile support equipment. The primary HDD equipment would be powered by diesel engines ranging from 150 to 600 hp. The majority of equipment would be located on the drill entry site where the total connected power would be approximately 1,900 hp. The diesel engines would be mounted on skids or trailers and equipped with exhaust mufflers. Equipment requirements may be slightly reduced for shallow HDD crossings less than 1,000 feet (e.g., no mud pump at drill exit site).

At most locations, HDD operations would be conducted for 12 hours per day during daytime or daylight hours. Due to its extended length and depth, drilling equipment at HDD Site No. C-24-03 (St. Croix River) would operate 24 hours per day to improve the likelihood of completing a successful drill and reducing the number of days that drilling would be required. Drilling may also be conducted during nighttime hours at other sites depending upon subsurface conditions. Most HDD crossings would be completed in 15 days or less. The estimated duration of the longer crossings ranges from 24 days for HDD Site No. C-29-171 to 75 days for HDD Site No. C-24-03. Drilling may require longer durations where an initial drill fails or difficult subsurface conditions are encountered. Estimates of the expected number of days for drilling operations are provided in table 4.11.2.4-1.

Existing ambient $L_{dn}$ at NSAs near drill entry and exit sites have been estimated from previous ambient sound level monitoring conducted in June 2006 in the vicinity of the proposed terminal site in Robbinston, Maine. For each HDD location, the estimated $L_{dn}$ values have been calculated based on the distance of the nearest NSA to U.S. Route 1, which is a prominent existing noise source in the vicinity of the proposed pipeline route.

TABLE 4.11.2.4-1

**Location, Estimated Length, and Estimated Duration of HDD Crossings**

| HDD Site No. | Milepost | Estimated Length of HDD Crossing in Feet | Estimated Duration of HDD Activity (Days) |
|---|---|---|---|
| R-09-15 | 1.2 | 1,850 | 23 |
| R-06-03 | 3.2 | 850 | 10 |
| R-03-03 | 3.6 | 530 | 7 |
| R-03-04 | 4.2 | 1,270 | 16 |
| C-37-224 | 5.1 | 740 | 8 |
| C-37-109-01 | 6.7 | 210 | 4 |
| C-33-112 | 8.6 | 2,750 | 31 |
| C-32-97 | 9.0 | 630 | 8 |

TABLE 4.11.2.4-1

**Location, Estimated Length, and Estimated Duration of HDD Crossings**

| HDD Site No. | Milepost | Estimated Length of HDD Crossing in Feet | Estimated Duration of HDD Activity (Days) |
|---|---|---|---|
| C-32-131 | 9.2 | 690 | 9 |
| C-32-135 | 9.5 | 580 | 7 |
| C-29-147 | 10.4 | 690 | 9 |
| C-29-171 | 12.0 | 2,480 | 25 |
| C-26-14 | 12.8 | 740 | 7 |
| C-24-03 | 14.6 | 6,650 | 75 |
| BP-06-03 | 18.0 | 2,480 | 40 |
| B-11-02 | 21.3 | 320 | 4 |
| B-14-15 | 24.4 | 690 | 9 |
| B-03-14 | 25.2 | 2,750 | 34 |
| B-03-15A1 | 29.0 | 1,110 | 13 |
| B-03-15A2 | 29.2 | 1,000 | 13 |
| B-03-15A3 | 29.8 | 690 | 8 |

Based on field measurements of similar HDD activity for pipeline construction, the combined sound level from the drilling equipment at the entry sites is expected to be no more than 77 dBA at 196 feet. For each HDD crossing, sound level estimates from HDD operation have been calculated at the nearest residential NSA and the Moosehorn NWR boundary to drill entry and exit points. Although sound levels at exit sites may be lower than entry sites, these estimates were derived using sound levels for drill entry sites and calculating attenuation due to distance and atmospheric absorption. Measured source levels and calculated sound levels at NSAs and the Moosehorn NWR boundary are presented in table 4.11.2.4-2. Actual sound levels may vary from those presented in table 4.11.2.4-2. In some cases, received sound levels may be less than predicted due to additional attenuation provided by intervening terrain and vegetation that has not been factored into the calculations.

TABLE 4.11.2.4-2

**Estimated HDD Sound Levels at the Nearest NSA and Moosehorn NWR**

| HDD Site No. | Access Point Milepost | Distance to NSA (ft) | Estimated Sound Level at NSA (dBA) a/ | Distance to Moosehorn NWR (ft) | Estimated Sound Level (dBA) a/ |
|---|---|---|---|---|---|
| R-09-15 | 1.11 –Exit | 449 | 68 | > 12,000 | <35 |
| | 1.46 – Entry | 105 | 82 | > 12,000 | <35 |
| R-06-03 | 3.09 – Exit | 1,348 | 56 | > 12,000 | <35 |
| | 3.25 – Entry | 907 | 61 | > 12,000 | <35 |
| R-03-03 | 3.64 – Entry | 1,420 | 56 | > 12,000 | <35 |
| | 3.74 – Exit | 1,880 | 52 | > 12,000 | <35 |
| R-03-04 | 4.13 – Exit | 2,595 | 47 | > 12,000 | <35 |
| | 4.37 – Entry | 1,634 | 54 | > 12,000 | <35 |
| C-37-224 | 5.09 – Entry | 293 | 73 | > 12,000 | <35 |
| | 5.23 – Exit | 470 | 68 | > 12,000 | <35 |
| C-37-109-01 | 6.68 – Entry | 5,066 | 36 | > 12,000 | <35 |

TABLE 4.11.2.4-2

**Estimated HDD Sound Levels at the Nearest NSA and Moosehorn NWR**

| HDD Site No. | Access Point Milepost | Distance to NSA (ft) | Estimated Sound Level at NSA (dBA) a/ | Distance to Moosehorn NWR (ft) | Estimated Sound Level (dBA) a/ |
|---|---|---|---|---|---|
| | 6.72 - Exit | 5,183 | 36 | > 12,000 | <35 |
| C-33-112 | 8.30 – Entry | 2,555 | 47 | 8,200 | <35 |
| | 8.82 – Exit | 1,432 | 56 | 6,200 | <35 |
| C-32-97 | 8.96 – Exit | 1,252 | 57 | 5600 | <35 |
| | 9.08 – Entry | 1,453 | 55 | 5300 | 35 |
| C-32-131 | 9.18 – Entry | 1,863 | 52 | 4800 | 37 |
| | 9.31 – Exit | 1,544 | 55 | 4500 | 38 |
| C-32-135 | 9.48 – Entry | 688 | 64 | 3500 | 43 |
| | 9.59 – Exit | 231 | 75 | 2900 | 46 |
| C-29-147 | 10.38 – Exit | 644 | 65 | 500 | 67 |
| | 10.51 – Entry | 1,232 | 57 | 800 | 62 |
| C-29-171 | 11.74 – Entry | 3,716 | 42 | 3600 | 42 |
| | 12.21 – Exit | 5,844 | <35 | 1600 | 54 |
| C-26-14 | 12.75 – Exit | 3,839 | 41 | 50 | 89 |
| | 12.89 – Entry | 3,432 | 43 | 50 | 89 |
| C-24-03 | 14.08 – Entry | 937 | 61 ($L_{dn}$ = 67) | 700 | 64 ($L_{dn}$ = 70) |
| | 15.34 – Exit | 851 | 62 ($L_{dn}$ = 68) | 1000 | 60 ($L_{dn}$ = 66) |
| BP-06-03 | 17.70 –Entry | 384 | 70 | 250 | 74 |
| | 18.17 – Exit | 743 | 63 | 2200 | 50 |
| B-11-02 | 21.26 – Entry | 1,228 | 58 | > 12,000 | <35 |
| | 21.32 – Exit | 903 | 61 | > 12,000 | <35 |
| B-14-15 | 24.28 – Exit | 120 | 81 | > 12,000 | <35 |
| | 24.41 – Entry | 197 | 76 | > 12,000 | <35 |
| B-03-14 | 25.06 – Exit | 2,719 | 46 | > 12,000 | <35 |
| | 25.58 – Entry | 2,331 | 49 | > 12,000 | <35 |
| B-03-15A1 | 28.81 – Exit | 5,083 | 36 | > 12,000 | <35 |
| | 29.02 – Entry | 5,734 | <35 | > 12,000 | <35 |
| B-03-15A2 | 29.15 – Exit | 6,341 | <35 | > 12,000 | <35 |
| | 29.34 – Entry | 7,252 | <35 | > 12,000 | <35 |
| B-03-15A3 | 29.68 – Exit | 9,634 | <35 | > 12,000 | <35 |
| | 29.81 – Entry | 8,970 | <35 | > 12,000 | <35 |

a/ Hourly equivalent sound level except at HDD C-24-03, where $L_{dn}$ is also shown to reflect 24 hour per day drilling.

From measurements of similar HDD operations, estimates show that sound levels within approximately 1,500 feet of the drill site would have the potential to exceed 55 dBA. Where 24-hour drilling is necessary and $L_{dn}$ sound levels at NSAs are expected to exceed 55 dBA, Downeast would reduce noise levels at the NSAs by implementing noise control measures such as full or partial equipment enclosures, enhanced exhaust mufflers, and temporary noise barriers. These mitigation measures would reduce sound levels from HDD operations up to levels ranging from 10 to 15 dBA. To ensure that this mitigation is sufficient, **we recommend that:**

- **Prior to construction of the pipeline facilities, Downeast should file with the Secretary, for the review and written approval by the Director of OEP, an HDD noise mitigation plan for HDDs R-09-15, C-34-224, C-32-135, C-29-147, C-24-03, BP-06-03, and BP-14-15. The plan should identify mitigation measures designed to**

**reduce the noise impacts on the NSAs from HDD activities. During drilling operations, Downeast should implement the approved plan, monitor noise levels, and make all reasonable efforts to restrict the noise attributable to the drilling operations to no more than an $L_{dn}$ of 55 dBA at the NSAs.**

In addition, **we recommend that:**

- **Downeast should file in its weekly construction status reports the following for HDD operations that last more than 10 days:**
  - **a. the HDD entry point noise measurements from the nearest NSA, obtained at the start of drilling operations;**
  - **b. the noise mitigation that Downeast implemented prior to the start of drilling operations; and**
  - **c. any additional mitigation measures that Downeast would implement if the initial noise measurements exceeded an $L_{dn}$ of 55 dBA at the nearest NSA.**

By Maine law, construction activity such as HDD work is exempt from the Maine DEP noise regulation during daytime (7 a.m. to 7 p.m.) or daylight hours, whichever is longer. Downeast would be required to apply noise mitigation to meet Maine DEP noise limits during nighttime HDD operations.

Downeast has proposed using HDD to avoid impacts on several residences that are within 50 feet of the sendout pipeline construction right-of-way (see section 4.7.2). We have concurred with these HDD route variations and require that Downeast conduct noise analyses prior to construction to assess the impacts on the NSAs in these locations.

#### 4.11.2.4.2 Pipeline Operation Noise Impacts

The buried pipeline would not contribute to aboveground noise levels. Operational noise associated with the sendout pipeline would be limited to the immediate vicinity of the three mainline block valves, located at each end of the pipeline and at MP 17.2. Some minor noise may be heard immediately around the metering station; however, the meter station is located within the LNG terminal site. To ensure that the noise impacts at the NSA near the meter station do not exceed 55 dBA Ldn, we have included the meter station in our recommendation above (see section 4.11.2.3.3) that Downeast file a full load noise survey with the Secretary no later than 60 days after placing the Downeast LNG terminal and meter station into service. If the noise attributable to the operation of the Downeast LNG terminal and meter station exceeds 55 dBA $L_{dn}$ at any nearby NSAs, Downeast should install additional noise controls to meet the level within 1 year of the in-service date.

With implementation of the measures proposed by Downeast and our recommendations, impacts related to noise during construction and operation would be not be significant at the nearest NSAs, sensitive species, or aquatic habitats. In addition, we require that Downeast comply with our requirement to ensure that there would be no perceptible vibration at NSAs from operation of the LNG terminal. During operation, noise would be negligible, except for the meter station and the LNG terminal, which would constitute a minor to moderate long term noise impact.

## 4.12 RELIABILITY AND SAFETY

### 4.12.1 Regulatory Agencies

Three federal agencies share regulatory authority over the siting, design, construction and operation of LNG import terminals: the Coast Guard, the DOT, and the FERC. The Coast Guard regulates the safety of an LNG facility's marine transfer area and LNG marine traffic, and regulates security plans for the entire LNG facility and LNG marine traffic. Those standards are codified in 33 CFR 105 and 127. The DOT establishes federal safety standards for siting, construction, operation, and maintenance of onshore LNG facilities, as well as for the siting of marine cargo transfer systems at waterfront LNG plants. Those standards are codified in 49 CFR 193. Under the Natural Gas Act and delegated authority from the U.S. Department of Energy (DOE), the FERC authorizes the siting and construction of LNG import and export facilities.

In 1985, the FERC and DOT entered into a Memorandum of Understanding regarding the execution of each agency's respective statutory responsibilities to ensure the safe siting and operation of LNG facilities. In addition to FERC's existing ability to impose requirements to ensure or enhance the operational reliability of LNG facilities, the Memorandum of Understanding specified that FERC may, with appropriate consultation with DOT, impose more stringent safety requirements than those in Part 193.

In February 2004, the Coast Guard, DOT, and FERC entered into an Interagency Agreement to ensure greater coordination among these three agencies in addressing the full range of safety and security issues at LNG terminals, including terminal facilities and tanker operations, and maximizing the exchange of information related to the safety and security aspects of the LNG facilities and related marine operations. Under the Interagency Agreement, the FERC is the lead federal agency responsible for the preparation of the analysis required under NEPA for impacts associated with terminal construction and operation. The DOT and Coast Guard, when necessary, participate as cooperating agencies.

As part of the review required for a FERC authorization, Commission staff must ensure that all proposed facilities operate safely and securely. The design information that must be filed in the application to the Commission is specified by Title 18 CFR 380.12 (m) and (o). The level of detail necessary for this submittal requires the project sponsor to perform substantial front-end engineering of the complete facility. The design information is required to be site-specific and developed to the extent that further detailed design would not result in changes to the siting considerations, basis of design, operating conditions, major equipment selections, equipment design conditions, or safety system designs which we considered during our review process. FERC's filing regulations also require each applicant to identify how its proposed design would comply with DOT's siting requirements of 49 CFR 193, Subpart B. As part of our NEPA review, we use this information from the applicant, developed to comply with DOT's regulations, to assess whether or not a facility would have a public safety impact. As a cooperating agency, DOT assists FERC staff in evaluating whether an applicant's proposed siting meets the DOT requirements. If a facility is constructed and becomes operational, the facility would be subject to DOT's inspection program. Final determination of whether a facility is in compliance with the requirements of 49 CFR 193 would be made by DOT staff.

In accordance with 33 CFR 127, the Coast Guard provided FERC with an LOR regarding the suitability of the waterway for LNG carrier traffic. Section 4.12.7 includes the results of the Coast Guard's review on waterway suitability.

### 4.12.2 Hazards

The principal hazards associated with the storage and vaporization of LNG result from loss of containment, vapor dispersion characteristics, flammability, and the ability to produce damaging overpressures. A loss of the containment provided by storage tanks, process piping, or equipment (pumps, vaporizers, etc.) would result in the formation of flammable vapor near the release location, as well as near LNG that pooled. Releases occurring in the presence of an ignition source would most likely result in a fire located at the vapor source. A spill without ignition would form a vapor cloud that would travel with the prevailing wind until it either dispersed below the flammable limits or encountered an ignition source. In some instances, ignition of a vapor cloud may produce damaging overpressures. These hazards are described in more detail below.

***Loss of Containment***

A loss of the containment is the initial event that results in all other potential hazards. The initial loss of containment can result in a liquid and/or gaseous release with the formation of vapor at the release location, as well as from any liquid that pooled. The fluid released may present low or high temperature hazards, and may result in the formation of flammable vapors. The extent of the hazard will depend on the material released, the storage and process conditions, and the volumes released.

Downeast would store LNG on-site at atmospheric pressure and at a cryogenic temperature of approximately -260 degrees Fahrenheit (°F). Loss of containment of LNG could lead to the release of both liquid and vapor into the immediate area. Exposure to either cold liquid or vapor could cause freeze burns and, depending on the length of exposure, more serious injury or death. However, spills would be contained within the terminal and the cold state of these releases would be greatly limited due to the continuous mixing with the warmer air. The cold temperatures from the release would not present a hazard to any person outside the terminal.

LNG is a cryogenic liquid that quickly cools any materials contacted by the liquid on release, causing extreme thermal stress in materials not specifically designed for such conditions. These thermal stresses could subsequently subject the material to brittleness, fracture, or other loss of tensile strength. These temperatures, however, would be accounted for in the design of equipment and structural supports, and would not be substantially different from the hazards associated with the storage and transportation of liquid oxygen (-296ºF) or several other cryogenic liquids that have been routinely produced and transported in the United States.

A rapid phase transition (RPT) can occur when a cryogenic liquid is spilled onto water and changes from liquid to gas, virtually instantaneously. Unlike an explosion that releases energy and combustion products from a chemical reaction, an RPT is the result of heat transferred to the liquid inducing a change to the vapor state. RPTs have been observed during LNG test spills onto water. In some test cases, the overpressures generated were strong enough to damage test equipment in the immediate vicinity of the LNG release point. The sizes of the overpressure events have been generally small and are not expected to cause significant damage. The average overpressures recorded at the source of the RPTs during the Coyote tests have ranged from 0.2 pounds per square inch (psi) to 11 psi[28]. These events are typically limited to the area within the spill and are not expected to cause damage outside of the area engulfed by the LNG pool. However, a RPT may affect the rate of pool spreading and the rate of vaporization for a spill on water.

***Vapor Dispersion***

In the event of a loss of containment, LNG would vaporize when released from any storage or process facilities. Depending on the size of the release, LNG may form a liquid pool and vaporize. Additional vaporization would result from exposure to ambient heat sources, such as water or soil. When released from a containment vessel or transfer system, LNG will generally produce 620 to 630 standard cubic feet of natural gas for each cubic foot of liquid.

If the loss of containment does not result in immediate ignition of the natural gas vapors, the vapor cloud would travel with the prevailing wind until it either encountered an ignition source or dispersed below its flammable limits. An LNG release would form a denser-than-air vapor cloud that would sink to the ground due to the cold temperature of the vapor. As the LNG vapor cloud disperses downwind and mixes with the warm surrounding air, the LNG vapor cloud may become buoyant. However, experimental observations and vapor dispersion modeling indicate the LNG vapor cloud would not typically be warm, or buoyant, enough to lift off from the ground before the LNG vapor cloud becomes too diluted to be flammable. As a result, estimating the dispersion of the vapor cloud is an important step in addressing potential hazards and is discussed in section 4.12.5 of this EIS.

Methane, the primary component of LNG, is classified as a simple asphyxiate and may pose extreme health hazards, including death, if inhaled in significant quantities within a limited time. Very cold methane vapors may also cause freeze burns. However, the locations of concentrations where cold temperatures and oxygen-deprivation effects could occur are greatly limited due to the continuous mixing with the warmer air surrounding the spill site. Exposure injuries from contact with releases of methane normally represent negligible risks to the public.

***Vapor Cloud Ignition***

Flammability of the LNG vapor cloud would be dependent on the concentration of the vapor when mixed with the surrounding air. In general, higher concentrations within the vapor cloud would exist near the spill, and lower concentrations would exist near the edge of the cloud as it disperses downwind. Mixtures occurring between the lower flammability limit (LFL) and the upper flammability limit (UFL) could be ignited. Concentrations above the UFL or below the LFL would not ignite. The LFL and UFL for methane are approximately 5 percent by volume (%-vol) and 15%-vol in air, respectively. If the flammable portion of a vapor cloud encounters an ignition source, a flame would propagate through the flammable portions of the cloud. In most circumstances, the flame would be driven by the heat it generates, a process known as a deflagration. A methane vapor cloud deflagration in an uncongested and unconfined area travels at slower speeds and does not produce significant pressure waves. Confined and congested

[28] The Lawrence Livermore National Laboratory conducted seven tests (the Coyote series) on vapor cloud dispersion, vapor cloud ignition, and RPTs at the Naval Weapons Center in China Lake, California in 1981.

methane vapor clouds may produce higher flame speeds and overpressures, and are discussed later in section 4.12.5 under "Overpressure Considerations."

A deflagration may propagate back to the spill site if the vapor concentration along this path is sufficiently high to support the combustion process. When the flame reaches vapor concentrations above the UFL, the deflagration could transition to a fireball and result in a pool or jet fire back at the spill source. A fireball could occur if the fire reaches a fuel rich portion of the cloud, such as near the source of the release, and would be of a relatively short duration compared to an ensuing jet or pool fire.

The extent of the affected area and the severity of the impacts on objects either within an ignited cloud or in the vicinity of a pool fire would primarily be dependent on the quantity and duration of the initial release, the surrounding terrain, and the environmental conditions present during the dispersion of the cloud. Radiant heat and dispersion modeling for the on-shore facilities are discussed in section 4.12.5. Impacts from LNG spills over water along the LNG carrier transit route are discussed in section 4.12.7.

A vapor cloud fire can ignite combustible materials within the cloud and can also cause severe burns and death. Resultant pool and jet fires may also cause failures of nearby storage vessels, piping, and equipment. The failure of a pressurized vessel could cause fragments of material to fly through the air at high velocities, posing damage to surrounding structures and a hazard for operating staff, emergency personnel, or other individuals in proximity to the event. In addition, failure of a pressurized vessel when the liquid is at a temperature significantly above its normal boiling point could result in a boiling-liquid-expanding-vapor explosion (BLEVE). BLEVEs of flammable liquids can produce overpressures and a subsequent fireball when the superheated liquid rapidly changes from a liquid to a vapor upon the release from the vessel. Atmospheric storage tanks, such as those proposed for LNG storage in this project are unlikely to BLEVE due to their lower design pressures.

***Overpressures***

If the deflagration in a flammable vapor cloud accelerates to a sufficiently high rate of speed, pressure waves would be generated. As a deflagration accelerates to super-sonic speeds, larger pressure waves are produced, and a shock wave created. This shock wave, rather than the heat, would begin to drive the flame, resulting in a detonation. Deflagrations or detonations are often characterized more generally as explosions when the rapid movement of the flame and pressure waves associated with them cause additional damage. The amount of damage an explosion causes is dependent on the amount the pressure wave is above atmospheric pressure (i.e. an overpressure) and its duration (i.e., pulse). For example, a 1 psi overpressure is often cited as a safety limit in regulations and is associated with glass shattering and traveling with velocities high enough to lacerate skin. Flame speeds and overpressures are primarily dependent on the reactivity of the fuel, the ignition strength and location, the degree of congestion and confinement of the area occupied by the vapor cloud, and the flame travel distance.

The potential for detonation of a vapor cloud is given special attention because it would produce much higher consequences; however, detonation is not the only scenario of concern. Large overpressures can still exist from high-order deflagrations and the propensity of a vapor cloud to deflagrate with damaging overpressures is similarly influenced by the fuel composition, level of confinement, and congestion (i.e., turbulence) surrounding the vapor cloud. However, it is still important to understand the potential of each occurrence, as explained below.

The potential for unconfined LNG vapor cloud detonations was investigated by the Coast Guard in the late 1970s at the Naval Weapons Center in China Lake, California. Using methane, the primary component of natural gas, several experiments were conducted to determine whether unconfined LNG vapor clouds would detonate. Unconfined methane vapor clouds ignited with low-energy ignition sources (13.5 joules), produced flame speeds ranging from 12 to 20 miles per hour (mph). These flame speeds are much lower than the flame speeds associated with a deflagration with damaging overpressures or a detonation. The tests indicated unconfined methane-air mixtures could be ignited, but no test produced unconfined detonation.

The Coast Guard conducted additional series of tests to quantify explosion hazards of LNG spills. Phase I included an analytical evaluation of the possible magnitude and damage potential of a spill of LNG. Phase II included tests igniting a range of methane concentrations using small and large boosters in a 1.8-meter-long, 0.6-meter-diameter shock tube and spark ignition sources in both 3.6-meter-long, 0.6-meter-diameter shock tube and thin film hemispheres. The intent was to evaluate potential from deflagration to detonation in unconfined flammable vapor clouds. Additional phases were conducted for spills of LNG and LPG and gasoline onto water for comparative reasons. These phases involved additional thin film hemisphere tests to evaluate whether a detonation initiated by a high explosive charge or a detonation exiting a tube could be sustained within an unconfined flammable vapor cloud.

In Phase II, spark ignition tests yielded velocities ranging from 45-63 m/s with overpressures of 0.2 to 0.4 psi. The Coast Guard also performed 5 meter and 10 meter radius hemisphere tests of unconfined stoichiometric methane-air mixtures ignited by spark igniters in the center of the hemisphere. During the 5 meter tests, flame speeds were approximately 5.2-7.3 m/s and a pressure wave was not recorded, indicating the pressure was less than the approximately 1.5 psi lower limit of the pressure sensing equipment. In one of the tests, simple obstacles were added and in another test, open tubes were added. Both of these failed to significantly alter the flame velocity.

Large explosive charge tests yielded velocities ranging from 910 m/s to 1,050 m/s with overpressures of 5.4 to 7.8 bar (78 to 113 psi). However, it is unclear as to whether the tube was long enough to obtain an accurate measure of the pressure induced by the methane versus the booster ignition source. Two attempts were also made to detonate a stoichiometric methane air mixture in 5 meter hemispheres using explosive boosters. During these tests, flame speeds were observed to propagate much more slowly than the initial detonation product expansion, measured at approximately 34 m/s.

In an additional phase (Phase III), tests were conducted to examine the level of sensitivity of an unconfined cloud to the presence of heavier hydrocarbons, such as ethane and propane. A series of tests on ambient-temperature fuel mixtures of methane-ethane and methane-propane indicated that the addition of heavier hydrocarbons influenced the tendency of an unconfined vapor cloud to detonate. Tests utilizing 57.6%, 76.8%, 81.6%, 86.4%, and 90% methane with the remainder of the fuel mixture made up of heavier hydrocarbons were examined. Methane concentrations above 81.6% failed to produce a vapor cloud detonation. Tests with 86-96% methane near stoichiometric proportions using exploding charges as the ignition source produced overpressures of 4 bar (58 psi), which was approximately the same overpressure produced during the calibration test involving the exploding charge ignition source alone. It remains unclear that the overpressure was attributable to the vapor deflagration.

In the last phase (Phase V) of the project, tests were conducted to determine whether methane could sustain a detonation initiated by an ignition source with high explosives or from an existing detonation emerging from a culvert. Tests indicated that 10 meter radius vapor clouds of nearly pure methane (99.9%) would not detonate from high explosives and the flame speeds and pressures rapidly decreased after initiation of the explosive charge. The second set of experiments used sheet explosive to create a detonation wave in a 6-meter-long culvert (1.8- and 2.4-meter-diameter) buried vertically in the ground filled with a flammable mixture of LNG with a 5- and 10 meter radius unconfined methane-propane and heavier hydrocarbon-air vapor cloud at the exit of the culvert. The experiments indicated that an unconfined vapor cloud with methane concentrations above 85% could not sustain a detonation from a 1.8-meter-diameter culvert. The experiment also indicated that an unconfined vapor cloud with a methane concentration of 99.9% could not sustain a detonation from a 2.4-meter-diameter diameter culvert. However, the experiments indicated that an unconfined vapor cloud with methane concentrations of up to 94% could sustain a detonation from a 2.4-meter-diameter culvert.

A separate study investigated the detonation sensitivity of methane-ethane-air stoichiometric mixtures from pure methane-air to pure ethane-air. The results of tests indicated that very strong ignition sources were necessary to initiate a detonation with ethane concentrations greater than 10% in the fuel mixture (or approximately 1% of total fuel-air mixture).

Tests in the early 1970s also investigated the effects of ignition end location within a pipe. A 40-meter-long, 1.4-meter-diameter pipe with one open end and one closed end was filled with methane-air and ignited at the respective ends of the pipe to examine the difference in flame speeds. The highest flame speed was observed when the gas was ignited in the closed end and the other end was open. When ignition was at the open end, the flow velocity and the turbulence level ahead of the flame were very low and the flame propagated at low velocities through the pipe.

In the early 1980s, tests investigated the effects of repeated baffle plates inside a 10-meter-long, 2.5-meter-diameter pipe with one end open. Configurations using 1, 3, 5, and 6 equally spaced baffle plates with area blockage ratios of 16%, 30%, and 50% were examined. Using spark igniters, five equally spaced baffle plates with blockage ratios of 50% produced an average maximum overpressure of approximately 4 bar (58 psi) within the pipe, a maximum overpressure of 4.3 bar (62 psi) immediately outside of the pipe, and a maximum overpressure of 0.39 bar (6 psi) located 10 meters downstream of the pipe exit. Similar experiments were conducted using propane and found to produce an average maximum overpressure of approximately 7 bar (102 psi) within the pipe, a maximum overpressure of 13.9 bar (202 psi) immediately outside of the pipe, and a maximum overpressure of 0.61 bar (9 psi) located 10 meters downstream of the pipe exit.

Tests conducted in the late 1980s investigated whether flames propagating over and around repeated obstructions could generate high flame speeds. The tests ignited natural gas-air mixtures in a 45-meter-long long open-sided rig, in which pipe arrays, obstructions, and grids were located to simulate obstacles found on most gas processing and storage sites. The first set of tests had 1.5 meter spaced pipe arrays arranged with an area blockage ratio of approximately 40% over the first 18 meters of the test rig. Maximum flame speeds of approximately 50 m/s attained in the tests were up to 10 times higher than in unobstructed tests, but with peak overpressures in the range of only 0.4 to 1 psi.

Further tests were conducted with the same pipe array setup covering the first 22.5 meters of the test rig. Immediately after the flame emerged from the obstructed region into the unobstructed part of the cloud, the flame rapidly decelerated to a level that produced an overpressure less than 0.15 psi. Natural gas-air tests with the same pipe array setup spanning the full 45 meters of the test rig showed flame speeds of approximately 80 m/s with peak overpressure inside the test-rig of approximately 1.5 psi.

In an attempt to achieve a limiting flame speed for natural gas, the test-rig was modified to completely enclose the first 9 meters of the rig to study whether the flame speed would accelerate or decelerate from the flame emerging from the confined region. Pipe arrays were varied within the confined region to produce flame speeds emerging from the confined region between 100 and 1,000 m/s, but remained the same in the unconfined region. For experiments with initiating flame speeds from the confined area of less than approximately 500 m/s the flame rapidly decelerated to approximately 30 to 40 m/s. For experiments with initiating flame speeds from the confined area of 600 to 700 m/s, the flame sustained approximately 500 m/s over the full length of the test-rig. In a further test with an initiating flame speed from the confined area of 1,000 m/s, the flame initially decelerated and then sustained at approximately 500 m/s.

To confirm that congestion was needed to sustain the high flame speeds, an experiment was conducted in which obstacles were located only over the first half of the test-rig. Similar to the unconfined tests, these tests also showed that immediately after the flame emerged from the congested region into the unobstructed part of the cloud, the flame rapidly decelerated to less than 10 m/s at the end of the test-rig. Additional tests showed that rapid deceleration occurred once the blockage ratio was reduced below 24% or the spacing between arrays exceeded 2.4 meters.

It was also shown that although more closely packed pipe arrays (down to 0.5 meters) could produce high flame speeds, there was not any evidence to suggest that in a longer region of more closely spaced pipe arrays (down to 0.5 meters) that higher flame speeds would have occurred compared to the previous tests.

Later tests of near stoichiometric proportions of methane-air were also conducted by the Explosion Research Cooperative to form the updated Baker-Strehlow-Tang (BST) blast wave curves for low reactivity substances. The tests ignited methane-air mixtures in an unconfined 12-ft-wide by 48-ft-long by 6-ft-high module test rig consisting of a 2x8 array of 6 foot cubical modules. Each 6 foot cubical module was outfitted with 2-inch-diameter schedule 40 pipe arrays of varying congestion. The low congestion set of tests had a 4x4 array of pipes with a pitch to diameter ratio of 7.6, an area blockage ratio of approximately 13% and volume blockage ratio of approximate 1.5%. The medium congestion set of tests had a 7x7 array of pipes with a pitch to diameter ratio of 4.3, an area blockage ratio of approximately 23% and volume blockage ratio of approximate 4.3%. The high congestion set of tests had alternating rows of 4 and 7 pipes with a pitch to diameter ratio of 3.1, an area blockage ratio of approximately 23% and volume blockage ratio of approximate 5.7%. According to those tests that form the BST blast wave curves, methane should not produce high flame speeds or associated large overpressures in areas of low congestion, even with partial confinement.

Numerous tests, reflective of offshore facilities, have also been conducted. These tests have shown similar trends of increased confinement and congestion resulting in larger overpressures. However, offshore facilities are not necessarily reflective of onshore, as offshore facilities are generally more congested and often contain multiple platform levels that can provide for confinement. This increase in congested and confinement can be attributed to the smaller footprint associated with offshore facilities.

This history of natural gas explosion tests provides a frame of reference for informing our site-specific evaluation on the potential for LNG facilities to produce damaging overpressures. To examine the potential for detonation of an unconfined natural gas cloud containing heavier hydrocarbons that are more reactive, such as ethane and propane, the Coast Guard conducted further tests on ambient-temperature fuel mixtures of methane-ethane and methane-propane. The tests indicated that the addition of heavier hydrocarbons influenced the tendency of an unconfined natural gas vapor cloud to detonate. Natural gas with greater amounts of heavier hydrocarbons would be more sensitive to detonation.

Although it is possible to produce damaging overpressures and detonations of unconfined LNG vapor clouds, the LNG proposed for importation to the Downeast project would have lower ethane and propane concentrations than those that resulted in damaging overpressures and detonations. The substantial amount of initiating explosives needed to create the shock initiation during the limited range of vapor-air concentrations also renders the possibility of detonation of these vapors at an LNG plant as unrealistic. Ignition of a confined LNG vapor cloud could result in higher overpressures. In order to prevent such an occurrence, measures are taken to mitigate the vapor dispersion and ignition into confined areas, such as buildings. In general, the primary hazards to the public from an LNG spill that disperses to an unconfined area, either on land or water, would be from dispersion of the flammable vapors or from radiant heat generated by a pool fire. Discussion of these hazards and potential mitigation are in section 4.12.5 for the on-shore facilities and in section 4.12.7 for the LNG carrier transit route.

### *Past LNG Facility Incidents*

With the exception of the October 20, 1944, failure at an LNG facility in Cleveland, Ohio, the operating history of the U.S. LNG industry has been free of safety-related incidents resulting in adverse effects on the public or the environment. The 1944 incident in Cleveland led to a fire that killed 128 people and injured 200 to 400 people.[29] The failure of the LNG storage tank was due to the use of materials inadequately suited for cryogenic temperatures. LNG migrating through streets and into underground sewers, due to the lack of adequate spill impoundments at the site, was also a contributing factor. Current regulatory requirements ensure that proper materials suited for cryogenic temperatures are used and that spill impoundments are designed and constructed properly to contain a spill at the site.

[29] For a description of the incident and the findings of the investigation, see "U.S. Bureau of Mines, Report on the Investigation of the Fire at the Liquefaction, Storage, and Regasification Plant of the East Ohio Gas Co., Cleveland, Ohio, October 20, 1944," dated February 1946.

Another operational accident occurred in 1979 at the Cove Point LNG facility in Lusby, Maryland. A pump seal failure resulted in gas vapors entering an electrical conduit and settling in a confined space. When a worker switched off a circuit breaker, the gas ignited, causing heavy damage to the building and a worker fatality. With the participation of the FERC, lessons learned from the 1979 Cove Point accident resulted in changing the national fire codes to ensure that the situation would not occur again.

On January 19, 2004, a blast occurred at Sonatrach's Skikda, Algeria, LNG liquefaction facility, which killed 27 and injured 56 workers. No members of the public were injured. Findings of the accident investigation suggested that a cold hydrocarbon leak occurred at Liquefaction Train 40 and was introduced to the high-pressure steam boiler by the combustion air fan. An explosion developed inside the boiler firebox, which subsequently triggered a larger explosion of the hydrocarbon vapors in the immediate vicinity. The resulting fire damaged the adjacent liquefaction process and liquid petroleum gas separation equipment of Train 40, and spread to Trains 20 and 30. Although Trains 10, 20, and 30 had been modernized in 1998 and 1999, Train 40 had been operating with its original equipment since start-up in 1981. To ensure that this potential hazard is addressed at the proposed Project, Downeast would install hazard detection devices at all combustion and ventilation air intake equipment to enable isolation and deactivation of any combustion equipment whose continued operation could add to or sustain an emergency.

On March 31, 2014, an explosion and fire occurred at Northwest Pipeline Corporation's LNG peak-shaving facility in Plymouth, Washington. The facility was immediately shut down, and emergency procedures were activated, which included notifying local authorities and evacuating all plant personnel. No members of the public were injured. The accident investigation is still in progress. Once developed, measures to address any causal factors which led to this incident will be applied to all facilities under Commission jurisdiction.

### 4.12.3 Technical Review of the Preliminary Engineering Design

Operation of the proposed facility poses a potential hazard that could affect the public safety if strict design and operational measures to control potential accidents are not applied. The primary concerns are those events that could lead to an LNG spill of sufficient magnitude to create an off-site hazard as discussed in section 4.12.2. However, it is important to recognize the stringent requirements in place for the design, construction, operation, and maintenance of the facility, as well, as the extensive safety systems proposed to detect and control potential hazards.

As part of a project's preliminary safety review, Downeast's design development team conducted a hazard and operability review (HAZOP) analysis of the Front-End Engineering Design (FEED) to identify the major hazards that may be encountered during the operation of facilities. The HAZOP study addresses hazards of the process, engineering and administrative controls, and provides a qualitative evaluation of a range of possible safety, health, and environmental effects which may result from the design or operation of the facility. Recommendations to prevent or minimize these hazards are generated from the results of the HAZOP review. These studies help establish the required safety control levels and identify whether additional process and safety instrumentation, mitigation, and/or administrative controls would be needed. In addition, Downeast's design development team would perform another HAZOP review of the completed design during the detailed design phase.

Once the design has been subjected to a HAZOP review, the design development team tracks changes in the facility design, operations, documentation, and personnel. Downeast would evaluate these changes to ensure that the safety, health, and environmental risks arising from these changes are addressed and controlled. FERC staff would monitor resolutions of the recommendations generated by the HAZOP review of the final completed design. We have included a recommendation that Downeast should file a HAZOP study on the completed final design.

Based on these analyses, Downeast would include various layers of protection or safeguards would in the facility design to reduce the risk of a potentially hazardous scenario from developing into an event that could impact the off-site public. These layers of protection are independent of one another so that anyone would perform its function regardless of the action or failure of any other protection layer or initiating event. These layers of protection typically include:

- A facility design that prevents hazardous events through the use of suitable materials of construction; operating and design limits for process piping, process vessels, and storage tanks; adequate design for wind, flood, seismic, and other outside hazards;
- Control systems, including monitoring systems and process alarms, remotely-operated control and isolation valves, and operating procedures to ensure the facility stays within the established operating and design limits;
- Safety-instrumented prevention systems, such as safety control valves and emergency shutdown systems, to prevent a release if operating and design limits are exceeded;
- Physical protection systems, such as appropriate electrical area classification, proper equipment and building spacing, pressure relief valves, spill containment, and structural fire protection, to prevent escalation to a more severe event;
- Site security measures for controlling access to the facility, including security inspections and patrols; response procedures to any breach of security; and liaison with local law enforcement officials; and
- On-site and off-site emergency response, including hazard detection and control equipment, firewater systems, and coordination with local first responders to mitigate the consequences of a release and prevent it from escalating to an event that could impact the public.

The use of these protection layers would mitigate the potential for an initiating event to develop into an incident that could damage the facility, injure operating staff, or impact the safety of the off-site public. In addition, siting of the facility with regard to potential off-site consequences is required by DOT's regulations in 49 CFR 193, Subpart B to ensure that impact on the public would be minimized. These siting requirements are discussed in section 4.12.4.

As part of the application, Downeast provided a FEED for the project. The FEED and specifications submitted for the proposed facilities to date are preliminary, but would serve as the basis for any detailed design to follow. During the FERC review process, we analyzed the information filed by Downeast to determine the extent that layers of protection or safeguards to enhance the safety, operability, and reliability of the facility are included in the FEED.

As a result of the technical review of the information provided by Downeast in the submittal documents, we identified a number of concerns relating to the reliability, operability, and safety of the proposed design. In response to staff's questions, Downeast provided written responses prior to the technical conference held on April 25, 2007. However, some of these responses indicated that corrections or modifications would be made to the design in order to address issues raised in the information request. As a result, **we recommend that**:

- **<u>Prior to construction of the final design</u>, Downeast should provide information/revisions related to those responses in their April 10, 2007 filing that state that corrections or modifications would be made to the design. The final design should specifically address response numbers 2, 8, 10, 13, 15, 23, 24, 25, 26, 27, 30, 31, 33, 34, 38, 51, 54, 56, 59, 61, and 70 using management of change procedures.**

The objectives of our FEED review focused on the engineering design and safety concepts of the various protection layers, as well as the projected operational reliability of the proposed facilities. The design would use materials of construction suited to the pressure and temperature conditions of the process design. Piping would be designed in accordance with American Society of Mechanical Engineers (ASME) B31.3. Pressure vessels would be designed in accordance with ASME Section VIII and the storage tanks would be designed in accordance with American Petroleum Institute (API) Standard 620 per 49 CFR 193 and the National Fire Protection Association's Standard 59A (NFPA 59A). Valves and other equipment would be designed to recommended and generally accepted good engineering practices. Downeast states it would design the LNG storage tanks to withstand the effects of hurricane force winds with a design wind velocity of 150 mph.

As part of its role as a cooperating agency on this document, DOT provided comments indicating that additional equipment should be designed to withstand this windspeed. DOT requires the use of an assumed sustained wind velocity of not less than 150 mph for all equipment used for transferring, storing, or vaporizing LNG. Alternative wind speeds may be approved by DOT provided they are justified by adequate wind data and an acceptable probabilistic methodology. As such, Downeast either must design the facilities to accommodate wind forces based on a sustained wind velocity of 150 mph or may request DOT approval for use of a lower wind speed under the regulatory means listed in § 193.2067(b). As a result, **we recommend that:**

- **<u>Prior to the construction of the final design</u>, Downeast should file with the Secretary for review and written approval by the Director of OEP, certification that the final design has been modified to be consistent with the wind speed requirements of 49 CFR § 193.2067 or that DOT has approved the use of a lower wind speed as allowed by § 193.2067(b). Downeast should consult with DOT on any actions necessary to demonstrate compliance with Part 193.**

All onshore structures at the terminal would be at a height of 50 feet or greater above sea level (North American Vertical Datum of 1988) to minimize the risk of flooding. The dock would be 19.1 feet NAVD88. These elevations exceed the 100 year and 500 year return period of 14.3 feet and 14.6 feet NAVD88, respectively. The onshore facilities would also be well above the predicted maximum water level of approximately 21 feet NAVD88 defined by NOAA for a Category 4 Hurricane for the area. As discussed in section 4.1.4, we also examined the seismic and structural design of the facility and provided recommendations to deal with the issues identified.

Downeast would install process control valves and instrumentation to safely operate and monitor the facility. Alarms would have visual and audible notification in the control room to warn operators that process conditions may be approaching design limits. Operators would have the capability to take action from the control room to mitigate an upset.

Downeast would develop facility operations procedures after completion of the final design; this timing is fully consistent with accepted industry practice. We are recommending that Downeast provide more information on the operating and maintenance procedures as they are developed, including safety procedures, hot work procedures and permits, abnormal operating conditions procedures, training of personnel. In addition, we are recommending measures, such as equipment/pipe labeling and valve car-seals/locks, to address human factor considerations and improve facility safety. An alarm management program would also be in place to ensure effectiveness of the alarms.

Safety valves and instrumentation would be installed to monitor, alarm, shutdown, and isolate equipment and piping during process upsets or emergency conditions. Safety instrumented systems would comply with International Society for Automation (ISA) Standard 84.01 and other recommended and generally accepted good engineering practices. We are also recommending changes to the design, installation, and commissioning of instrumentation and emergency shutdown equipment to ensure appropriate cause and effect alarm or shutdown logic and enhanced representation of the emergency shutdown valves in the facility control system.

Safety relief valves and vent stacks would be installed to protect the process equipment and piping. The safety relief valves would be designed to handle process upsets and thermal expansion within piping, per NFPA 59A and ASME Section VIII, and would be designed based on API 520, API 521, API 526, API 527, and other recommended and generally accepted good engineering practices. In addition, we are making recommendations for changes to the design and installation of pressure and vacuum relief devices to ensure appropriate discharge and separate handling of LNG and natural gas.

In order to minimize the risk of an intentional event, Downeast would provide security fencing, lighting, camera systems, and intrusion detection to deter, monitor, and detect intruders into the facility. In addition, as discussed in section 4.12.6, Downeast would be required to develop a Facility Security Plan in accordance with the Coast Guard's regulations found in 33 CFR 105, Subpart D. We are also recommending that Downeast provide site access control during construction and security and incident reporting during operation.

In the event of a release, Downeast would provide drainage systems from LNG storage and process facilities direct a spill away from equipment in order to minimize flammable vapors from dispersing to confined, occupied, or public areas and to minimize heat from impacting adjacent equipment and public areas if ignition occurs. Spacing of vessels and equipment between each other, from ignition sources, and to the property line would comply with 49 CFR Part 193 and 33 CFR Part 127.105. In addition, Coast Guard requiremented outline in 33 CFR Part 127.105 discuss LNG impounding spaces to minimize or prevent structural damage to an LNG vessel moored or berthed at a waterfront facility handling LNG. We are also making recommendations on the spacing and design of impoundments to minimize damage to equipment and buildings. Impoundment systems are further discussed in section 4.12.5.

Downeast performed a preliminary fire protection evaluation to ensure that adequate hazard detection, hazard control, and firewater coverage would be installed to detect and address any upset conditions. Structural fire protection, proposed to prevent failure of structural supports of equipment and piperacks, would comply with NFPA 59A and other recommended and generally accepted good engineering practices. Downeast would also install hazard detection systems to detect, alarm, and alert personnel in the area and control room to initiate an emergency shutdown and/or initiate appropriate procedures, and would meet NFPA 72, ISA 12.13, and other recommended and generally accepted good engineering practices. Hazard control devices would be installed to extinguish or control incipient fires and releases, and would meet NFPA 59A and NFPA 10, 11, 12, and 17 requirements, and other recommended and generally accepted good engineering practices. Automatic firewater systems and monitors would be provided for use during an emergency to cool the surface of storage vessels, piping, and equipment exposed to heat from a fire, and would meet NFPA 59A, 20, 22, 24, and 25 requirements. We are also making recommendations for the provision of a clean agent system in the power distribution building and for Downeast to provide a finalized fire protection evaluation. In addition, we are making recommendations for Downeast to provide more information on the design, installation, and commissioning of hazard detection, hazard control, and firewater systems as Downeast would further develop this information during the final design phase.

Downeast would also have emergency procedures in accordance with 49 CFR 193 and 33 CFR 127. The emergency procedures would provide for protection of personnel and the public as well as the prevention of property damage that may occur as a result of incidents at the facility. Downeast would also be required to develop an emergency response plan (ERP) in accordance with the Energy Policy Act of 2005 (EPAct 2005), as discussed further in section 4.12.8.

If authorization is granted by the Commission, the next phase of the project would include development of the final design, including final selection of equipment manufacturers, process conditions, and resolution of some safety-related issues. To ensure the final design would be consistent with the safety and operability characteristics identified in the FEED, information regarding the development of the final design, as detailed below, would need to be filed with the Secretary of the Commission (Secretary) for review and written approval by the Director of the Office of Energy Projects (OEP) before equipment construction at the site would be authorized.

In addition to the final design review, we would conduct inspections during construction and would review additional materials, including quality assurance and quality control plans, non-conformance reports, and cooldown and commissioning plans to ensure that the installed design would be consistent with the safety and operability characteristics of the FEED. We would also conduct inspections during operation to ensure that the facility would be operated and maintained in accordance with the filed design throughout the life of the facility.

To ensure that the concerns we identified relating to the reliability, operability, and safety of the proposed design are addressed by Downeast, and would be subject to the Commission's construction and operational inspection program, **we recommend that the following measures be applied to the Downeast LNG terminal. Information pertaining to these specific recommendations should be filed with the Secretary for review and written approval by the**

**Director of OEP either: prior to initial site preparation; prior to construction of final design; prior to commissioning; prior to introduction of hazardous fluids; or prior to commencement of service, as indicated by each specific condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 683 (Docket No. RM06-24-000), including security information, should be submitted as critical energy infrastructure information (CEII) pursuant to 18 CFR 388.112. See CEII Order No. 683, 71 Fed. Reg. 58,273 (October 3, 2006), FERC Stats. & Regs. ¶31,228 (2006). Information pertaining to items such as: offsite emergency response; procedures for public notification and evacuation; and construction and operating reporting requirements would be subject to public disclosure. All information should be filed a minimum of 30 days before approval to proceed is requested.**

- **Prior to initial site preparation, Downeast should file the quality assurance and quality control procedures for construction activities.**
- **Prior to initial site preparation, Downeast should include a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.**
- **Prior to initial site preparation, Downeast should file an overall project schedule.**
- **Prior to initial site preparation, Downeast should provide procedures for controlling access during construction.**
- **Prior to initial site preparation, Downeast should file a complete specification of the proposed LNG tank design and installation.**
- **Prior to initial site preparation, Downeast should file drawings of the storage tank piping support structure and support of horizontal piping at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances.**
- **Prior to initial site preparation, Downeast should file complete plan drawings of the security fencing and of facility access and egress, including the details of the fence and control access and egress from the pipe trestle and dock.**
- **The final design should provide change logs that list and explain any changes made from the Front-End Engineering Design provided in Downeast's application and filings. A list of all changes with an explanation for the design alteration should be provided and all changes should be clearly indicated on all diagrams and drawings.**
- **The final design should provide an equipment list, process and mechanical data sheets, and specifications.**
- **The final design should include spill containment system drawings with dimensions and slopes of curbing, trenches, and impoundments.**
- **The final design should include electrical area classification drawings.**
- **The final design should include the sizing basis and capacity for the final design of pressure and vacuum relief valves for major process equipment, vessels, storage tanks, and vent stacks.**

- **The <u>final design</u> should provide the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3, as required by 49 CFR 193.**
- **The <u>final design</u> should include up-to-date Process Flow Diagrams (PFDs) and Piping and Instrumentation Diagrams (P&IDs). The PFDs should include heat and material balances. The P&IDs should include the following information:**
  - **a. equipment tag number, name, size, duty, capacity, and design conditions;**
  - **b. equipment insulation type and thickness;**
  - **c. storage tank pipe penetration size or nozzle schedule;**
  - **d. piping with line number, piping class specification, size, and insulation type and thickness;**
  - **e. piping specification breaks and insulation limits;**
  - **f. all control and manual valves numbered;**
  - **g. valve high pressure side and internal and external vent locations;**
  - **h. relief valves with set points; and**
  - **i. drawing revision number and date.**
- **The <u>final design</u> should include an updated fire protection evaluation carried out in accordance with the requirements of NFPA 59A 2001, chapter 9.1.2 as required by 49 CFR 193. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations should be filed. The fire protection evaluation should address measures on the prevention of caustic water from entering the firewater tank.**
- **The <u>final design</u> should include complete drawings and a list of the hazard detection equipment. Drawings should clearly show the location and elevation of all detection equipment. The list should include the instrument tag number, type and location, alarm indication locations, set points, and shutdown functions of the proposed hazard detection equipment.**
- **The <u>final design</u> should provide a technical review of its proposed facility design that:**
  - **a. identifies all combustion/ventilation air intake equipment and the distances to any possible hydrocarbon release (LNG, flammable refrigerants, flammable liquids and flammable gases); and**
  - **b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shut down any combustion equipment whose continued operation could add to or sustain an emergency.**
- **The <u>final design</u> should provide drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Drawings should clearly show the location by tag number of all fixed, wheeled, and**

**hand-held extinguishers. The list should include the equipment tag number, type, capacity, equipment covered, discharge flow rate, and automatic and manual remote signals initiating discharge of the units.**

- **The <u>final design</u> should provide facility plans and drawings showing the location of the firewater and any foam systems. Drawings should clearly show: firewater and foam piping; post indicator valves; and the location, and area covered by, each monitor, hydrant, water curtain, deluge system, foam system, sprinkler system, and water mist system. The drawings should also include piping and instrumentation diagrams of the firewater and foam systems.**
- **The <u>final design</u> should specify that the design pressure of sendout equipment containing LNG in low pressure service should be not less than the design pressure of the piping system.**
- **The <u>final design</u> should specify that LNG relief valves and LNG drains should not discharge into the vapor system.**
- **The <u>final design</u> should specify that LNG from relief valves and drains is to be returned to storage.**
- **The <u>final design</u> should include provision for vehicle access roads to and from the north and south of the LNG pump and vaporizer area.**
- **The <u>final design</u> of the vapor return system should include provisions for the addition of LNG transfer pumps to the Jetty Drum D-103. The vapor inlet piping to the drum should be designed to ensure that all LNG, from the desuperheater and LNG piping discharging to the drum, cannot back flow to the vapor return piping.**
- **The <u>final design</u> should include provisions for the future installation of LNG pumps for the boil-off gas (BOG) drum.**
- **The <u>final design</u> should specify that the vapor inlet piping to the BOG drum should be designed to ensure that all LNG, from the desuperheater and LNG piping discharging to the drum, cannot back flow to the vapor return piping.**
- **The <u>final design</u> should specify that the Low Point Drain Drum is to be equipped to remove residual liquids without personnel accessing the spill containment sump.**
- **The <u>final design</u> of the Low Point Drain Drum should include a pressure relief system, to protect the vessel in the event of isolation.**
- **The <u>final design</u> of the boil-off condenser system should include a relief valve between the vapor inlet check valve and the fail-closed LNG outlet control valve.**
- **The <u>final design</u> should include provisions to recycle the boil-off compressor discharge to upstream of the BOG drum desuperheater.**
- **The <u>final design</u> should include car-seal or locked closed bypass valves around the intank pump ESD2 discharge valves as opposed to minimum stop set points for ESD2 valves, for cooldown of the 20-inch diameter header and piping.**

- **The <u>final design</u> should include a shutoff valve at the suction and discharge of each high pressure pump.**
- **The <u>final design</u> should specify that the minimum flow recycle line from the high pressure LNG pumps to downstream of the isolation valve to the LNG storage tanks should be the same pressure and temperature rating as the piping at the discharge of the high pressure LNG pumps.**
- **The <u>final design</u> should include a relief valve or operated vent valve sized for thermal relief at the discharge of each vaporizer, upstream of the isolation valves. This relief valve is in addition to the relief valve specified in NFPA 59A (2001 ed.) Section 5.4.1 and should be set at a lower pressure.**
- **The <u>final design</u> should include LNG tank fill flow measurement with high flow alarm.**
- **The <u>final design</u> should include a discretionary vent valve for each LNG tank, operable through the Distributed Control System (DCS).**
- **The <u>final design</u> should include BOG flow and temperature measurement for each tank.**
- **The <u>final design</u> should specify that all emergency shutdown (ESD) valves are to be equipped with open and closed position switches connected to the DCS/Safety Instrumented System (SIS).**
- **The <u>final design</u> should include a clean agent system in the power distribution building.**
- **The <u>final design</u> should include an analysis of the structural integrity of the outer containment of the full containment storage tanks when exposed to a roof tank top fire or adjacent tank top fire.**
- **The <u>final design</u> should specify that all drains from high pressure LNG systems are to be equipped with double isolation and bleed valves.**
- **The <u>final design</u> should specify that for hazardous fluids, branch piping, and piping nipples less than 2 inches are to be no less than Schedule 160.**
- **The <u>final design</u> should specify that piping and equipment that may be cooled with liquid nitrogen is to be designed for liquid nitrogen temperatures, with regard to allowable movement and stresses.**
- **The <u>final design</u> should include details of the shut-down logic, including cause and effect matrices for the process instrumentation, hazard detection system, and emergency shutdown system for alarms and shutdowns, including set points and voting logic.**
- **The <u>final design</u> should include emergency shutdown of equipment and systems activated by hazard detection devices for flammable gas, fire, and cryogenic spills, when applicable.**

- **The <u>final design</u> should include drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A.**
- **The <u>final design</u> should provide an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap should vent to a safe location and be equipped with a leak detection device that: should continuously monitor for the presence of a flammable fluid; should alarm the hazardous condition; and should shut down the appropriate systems.**
- **The <u>final design</u> should include a hazard and operability review of the completed design prior to issuing the P&IDs for construction. A copy of the review, a list of recommendations, and actions taken on the recommendations should be filed.**
- **The <u>final design</u> should include provisions to install high pressure boil-off compression or BOG liquefaction in the event that sendout operation is curtailed, or ceased for a period in excess of thirty days. Details should include plans and drawings of the BOG recovery system and specifications of the equipment and compressors to be installed.**
- **The <u>final design</u> should include provisions to remove LNG from the inlet of the vaporizer due to shutdown sequence.**
- **The <u>final design</u> should include a plan for clean-out, dry-out, purging, and tightness testing. This plan should address the requirements of the American Gas Association's Purging Principles and Practice required by 49 CFR 193, and should provide justification if not using an inert or non-flammable gas for cleanout, dry-out, purging, and tightness testing.**
- **The <u>final design</u> should include a vent stack dispersion analysis to determine the proper placement of hazard detection devices that ensures venting is done in a safe manner.**
- **The <u>final design</u> should specify that the vent stack be equipped with a discharge piece designed for ignited discharge conditions.**
- **<u>Prior to commissioning</u>, Downeast should file plans and detailed procedures for: testing the integrity of onsite mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service.**
- **<u>Prior to commissioning</u>, Downeast should provide a detailed schedule for commissioning through equipment startup. The schedule should include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids, and during commissioning and startup. Downeast should file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup will be issued.**
- **<u>Prior to commissioning</u>, Downeast should file results of the LNG storage tank hydrostatic test and foundation settlement results.**

- **<u>Prior to commissioning</u>, Downeast should tag all instrumentation and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.**
- **<u>Prior to commissioning</u>, Downeast should label equipment with equipment tag number and piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A.**
- **<u>Prior to commissioning</u>, Downeast should file the design details and procedures to record and to prevent the tank fill rate from exceeding the maximum fill rate specified by the tank designer.**
- **<u>Prior to commissioning</u>, Downeast should file operation and maintenance procedures and manuals, as well as safety procedures.**
- **<u>Prior to commissioning</u>, Downeast should maintain a detailed training log to demonstrate that operating staff has completed required training.**
- **<u>Prior to introduction of hazardous fluids</u>, Downeast should file a cooldown plan. During cooldown, Downeast should report progress on the development of cooldown in <u>daily</u> reports.**
- **<u>Prior to introduction of hazardous fluids</u>, Downeast should complete all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the Distributed Control System (DCS) and Safety Instrumented System (SIS) that demonstrates full functionality and operability of the system.**
- **<u>Prior to introduction of hazardous fluids,</u> Downeast should complete a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant should be shown on facility plot plan(s).**
- **<u>Prior to commencement of service</u>, Downeast should develop procedures for offsite contractors' responsibilities, restrictions, and limitations and for supervision of these contractors by Downeast staff.**
- **<u>Prior to commencement of service</u>, Downeast should notify FERC staff of any proposed revisions to the security plan and physical security of the facility.**
- **<u>Prior to commencement of service</u>, Downeast should file progress on construction of the LNG terminal in <u>monthly</u> reports. Details should include a summary of activities, problems encountered, contractor non-conformance/deficiency logs, remedial actions taken, and current project schedule. Problems of significant magnitude should be reported to the FERC <u>within 24 hours</u>.**

**In addition, the following measures should apply throughout the life of the facility:**

- **The facility should be subject to regular FERC staff technical reviews and site inspections on at least an <u>annual</u> basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, Downeast should respond to a specific data request including information relating to possible design and operating conditions that may have been imposed by other agencies or**

**organizations. Up-to-date detailed piping and instrumentation diagrams reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted annual report, should be submitted.**

- **Semi-annual operational reports should be filed with the Secretary to identify changes in facility design and operating conditions, abnormal operating experiences, activities (including ship arrivals/departures, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil-off/flash gas, etc.), and plant modifications including future plans and progress thereof. Abnormalities should include, but not be limited to: unloading/loading shipping problems, potential hazardous conditions caused by off-site transportation, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, nonscheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, vapor or liquid releases, fires involving natural gas and/or from other sources, negative pressure (vacuum) within a storage tank and higher than predicted boil-off rates. Adverse weather conditions and the effect on the facility should also be reported. Reports should be submitted within 45 days after each period ending June 30 and December 31. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" should also be included in the semiannual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facility.**

- **In the event the temperature of any region of any secondary containment, including imbedded pipe supports, becomes less than the minimum specified operating temperature for the material, the Commission should be notified within 24 hours and procedures for corrective action should be specified.**

- **Significant non-scheduled events, including safety-related incidents (e.g., LNG, refrigerant or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security related incidents (i.e., attempts to enter site, suspicious activities) should be reported to FERC staff. In the event an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification should be made immediately, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification should be made to FERC staff within 24 hours. This notification practice should be incorporated into the LNG facility's emergency plan. Examples of reportable LNG or refrigerant related incidents include:**

  a. **fire;**

  b. **explosion;**

  c. **estimated property damage of $50,000 or more;**

**d. death or personal injury necessitating in-patient hospitalization;**

**e. release of hazardous fluids for five minutes or more;**

**f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes gas, refrigerants, or LNG;**

**g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas, refrigerants, or LNG;**

**h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas, refrigerants, or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices;**

**i. a leak in an LNG facility that contains or processes gas, refrigerants, or LNG that constitutes an emergency;**

**j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;**

**k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operation of a pipeline or an LNG facility that contains or processes gas, refrigerants, or LNG;**

**l. safety-related incidents to LNG or refrigerant transportation occurring at or en route to and from the LNG facility; or**

**m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.**

**In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, FERC staff would determine the need for a separate follow-up report or follow-up in the upcoming semi-annual operational report. All company follow-up reports should include investigations results and recommendations to minimize a reoccurrence of the incident.**

### 4.12.4 Siting Requirements

The principal hazards associated with the substances involved in the, storage and vaporization of LNG result from cryogenic and flashing liquid releases; flammable vapor dispersion; vapor cloud ignition; pool fires; and overpressures. As discussed in section 4.12.3, our FEED review indicates that sufficient layers of protection would be incorporated into the facility design to mitigate the potential for an initiating event to develop into an incident that could impact the safety of the off-site public. Siting of the facility with regard to potential off-site consequences is also required by DOT's regulations in 49 CFR 193, Subpart B as an additional safeguard to help ensure that impact on the public would be minimized. The Commission's regulations under 18 CFR 380.12(o)(14) require Downeast to identify how the proposed design complies with DOT's siting requirements. As part of our review, we used Downeast's information, developed to comply with DOT's regulations, to assess whether or not the facility would have a public safety impact. The Part 193 requirements state that an operator or government agency must exercise control over the activities that can occur within an "exclusion zone," defined as the area around an LNG facility that could be exposed to specified levels of thermal radiation or flammable vapor in the event of a release. Approved mathematical models must be used to calculate the dimensions of these exclusion zones. The 2001 edition of NFPA 59A, an industry consensus safety standard for the siting, design, construction, operation, maintenance, and security of LNG facilities, is incorporated into Part 193 by reference, with regulatory preemption in the event of conflict. The following sections of Part 193 specifically address the siting requirements applicable to each LNG container and LNG transfer system:

- Part 193.2001, *Scope of part*, excludes any matter other than siting provisions pertaining to marine cargo transfer systems between the marine vessel and the last manifold or valve immediately before a storage tank.
- Part 193.2051, *Scope*, states that each LNG facility designed, replaced, relocated or significantly altered after March 31, 2000, must be provided with siting requirements in accordance with Subpart B and NFPA 59A (2001). In the event of a conflict with NFPA 59A (2001), the regulatory requirements in Part 193 prevail.
- Part 193.2057, *Thermal radiation protection*, requires that each LNG container and LNG transfer system have thermal exclusion zones in accordance with Section 2.2.3.2 of NFPA 59A (2001).
- Part 193.2059, *Flammable vapor-gas dispersion protection*, requires that each LNG container and LNG transfer system have a dispersion exclusion zone in accordance with Sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001).

For the LNG facilities proposed for this project, these Part 193 siting requirements would be applicable to the following equipment:

- Two 42,267,530 gallon (net) full containment LNG storage tanks and associated piping and appurtenances - Parts 193.2057 and 2059 require the establishment of thermal and flammable vapor exclusion zones for LNG tanks. NFPA 59A (2001), section 2.2.3.2 specifies four thermal exclusion zones based on the design spill and the impounding area. NFPA 59A (2001), sections 2.2.3.3 and 2.2.3.4 specify a flammable vapor exclusion zone for the design spill which is determined with section 2.2.3.5.
- A pier comprised of a single LNG carrier berth and a marine cargo transfer system, consisting of three 16-inch-diameter liquid transfer arms and one 16-inch-diameter vapor return arm, a single 36-inch-diameter LNG transfer pipe, and other associated process vessels, piping and appurtenances. Parts 193.2001, 2057, and 2059 require thermal and flammable vapor exclusion zones for the marine cargo transfer system. NFPA 59A (2001) does not address LNG transfer systems.

- Four 4,600 gallon per minute (gpm) low pressure in-tank pumps (two per tank; one operating and one spare) and associated piping and appurtenances; and four 1,400 gpm high pressure (HP) sendout pumps (three operating and one spare) and associated process vessels, piping, and appurtenances - Parts 193.2057 and 2059 require thermal and flammable vapor exclusion zones. NFPA 59A (2001) section 2.2.3.2 specifies the thermal exclusion zone and sections 2.2.3.3 and 2.2.3.4 specify the flammable vapor exclusion zone based on the design spills for containers and process areas.
- Four submerged combustion vaporizers (SCVs) and associated process vessels, piping, and appurtenances- Parts 193.2057 and 2059 require thermal and flammable vapor exclusion zones. NFPA 59A (2001) section 2.2.3.2 specifies the thermal exclusion zone and sections 2.2.3.3 and 2.2.3.4 specify the flammable vapor exclusion zone based on the design spill in a process area.

Previous FERC environmental assessments/impact statements for past projects have identified inconsistencies and areas of potential conflict between the requirements in Part 193 and NFPA 59A (2001). Sections 193.2057 and 193.2059 require exclusion zones for each LNG container and LNG transfer system, and an LNG transfer system is defined in section 193.2007 to include cargo transfer system and transfer piping (whether permanent or temporary). However, NFPA 59A (2001) requires exclusion zones only for "transfer areas," which is defined as the part of the plant where the facility introduces or removes the liquids, such as truck loading or ship-unloading areas. The NFPA 59A (2001) definition does not include permanent plant piping, such as cargo transfer lines. Section 2.2.3.1 of NFPA 59A (2001) also states that transfer areas at the water edge of marine terminals are not subject to the siting requirements in that standard.

The DOT addressed some of these issues in a March 2010 letter of interpretation.[30] In that letter, DOT stated that: (1) the requirements in the NFPA 59A (2001) for transfer areas for LNG apply to the marine cargo transfer system at a proposed waterfront LNG facility, except where preempted by the regulations in Part 193; (2) the regulations in Part 193 for LNG transfer systems conflict with the NFPA 59A (2001) on whether an exclusion zone analysis is required for transfer piping or permanent plant piping; and (3) the regulations in Part 193 prevailed as a result of that conflict. The DOT determined that an exclusion zone analysis of the marine cargo transfer system is required.

In FERC environmental assessments/impact statements for past projects, we also noted that when the DOT incorporated NFPA 59A into its regulations, it removed the regulation that required impounding systems around transfer piping. As a result of that change, it is unclear whether Part 193 or the adopted sections of NFPA 59A (2001) require impoundments for LNG transfer systems. We note that Part 193 requires exclusion zones for LNG transfer systems, and that those zones are calculated based on impoundment systems. We also note that the omission of containment for transfer piping is not a sound engineering practice. For these reasons, we generally recommend containment for all LNG transfer piping within a plant's property lines.

Federal regulations issued by the Occupational Safety and Health Administration (OSHA) under 29 CFR § 1910.119 (Process Safety Management of Highly Hazardous Chemicals; Explosives

[30] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) Interpretation "Re: Application of the Siting Requirements in Subpart B of 49 CFR Part 193 to the Mount Hope Bay Liquefied Natural Gas Transfer System" (March 25, 2010).

and Blasting Agents (PSM)), and the U.S. EPA under 40 CFR 68 (Risk Management Plans) cover hazardous substances, such as methane, propane and ethylene at many facilities in the United States. However, OSHA and EPA regulations are not applicable to facilities regulated under 49 CFR 193. On October 30, 1992, shortly after the promulgation of the OSHA PSM regulations, OSHA issued a letter of interpretation that precluded the enforcement of PSM regulations over gas transmission and distribution facilities. In a subsequent letter on December 9, 1998, OSHA further clarified that this letter of interpretation applies to LNG distribution and transmission facilities.

In addition, EPA's preamble to its final rule in Federal Register, Volume 63, Number 3, 639-645, clarified that exemption from the requirements in 40 CFR 68 for regulated substances in transportation, including storage incident to transportation, is not limited to pipelines. The preamble further clarified that the transportation exemption applies to LNG facilities subject to oversight or regulation under 49 CFR 193, including facilities used to liquefy natural gas or used to transfer, store, or vaporize LNG in conjunction with pipeline transportation.

### 4.12.5 Siting Analysis

Suitable sizing of impoundment systems and selection of design spills on which to base hazard analyses are critical for establishing an appropriate siting analysis. Although impoundment capacity and design spill scenarios for storage tank impoundments are well described by Part 193, a clear definition for other impoundments is not provided either directly by the regulations or by the adopted sections of NFPA 59A (2001). Under NFPA 59A (2001) Section 2.2.2.2, the capacity of impounding areas for vaporization, process, or LNG transfer areas must equal the greatest volume that can be discharged from any single accidental leakage source during a 10-minute period or during a shorter time period based upon demonstrable surveillance and shutdown provisions acceptable to the DOT. However, no definition of single accidental leakage source is provided in the regulations.

We recommend that impoundments be sized based on the greatest flow capacity from any single pipe for 10 minutes, recognizing that different spill scenarios may be used for the single accidental leakage sources for calculation of Part 193 exclusion zones. A similar approach is used with impoundments for process vessels. We expect these impoundments be able to contain the contents of the largest process vessel served, while recognizing that smaller design spills may be appropriate for Part 193 exclusion zone calculations.

#### *Impoundment Sizing*

Part 193.2181 references NFPA 59A (2001) for siting, which specifies each impounding system serving an LNG storage tank must have a minimum volumetric liquid capacity of 110 percent of the LNG tank's maximum design liquid capacity for an impoundment serving a single tank. We also consider it prudent design practice to provide a barrier to prevent liquid from flowing to an unintended area (i.e., outside the plant property) in the event that the full containment storage tank primary and secondary containers have a common cause failure. The purpose of the barrier is to prevent liquid from flowing off the plant property, and does not define containment or an impounding area for thermal radiation or flammable vapor exclusion zone calculations or other code requirements already met by sumps and impoundments throughout the site.

Downeast proposes two full-containment LNG storage tanks where the outer tank wall would serve as the impoundment system. As shown in table 4.12.5-1, the outer tank would have a volumetric capacity of 52,116,919 gallons, which exceeds the 110 percent requirement by 4,737,902 gallons. The outer tank would contain 116 percent capacity of the inner tank, meeting the Part 193 requirements. Downeast also proposes to install an earthen rock barrier around the LNG tanks and associated process area to limit liquid from flowing off the plant property in the case of a common cause failure of the full containment storage tank primary and secondary containers. The structure would be 21 feet in height for the barrier and would enclose an area of approximately 10 acres. The structure's volumetric capacity would contain a single LNG tank's maximum liquid capacity and would meet our recommendation that a barrier be provided to prevent liquid from flowing off plant property.

Downeast proposes three insulated concrete impoundment basins to contain possible LNG spills from piping and process areas: the Process Area Impoundment Basin; the Vaporizer Area Impoundment Basin; and the Transfer Area Impoundment Basin.

The Process Area Impoundment Basin would serve the curbed area around the LNG storage tanks and the in-tank pumps. In this area, the greatest flow capacity from a single transfer pipe would be from the in-tank pump withdrawal header. Although each tank has space for three pumps, Downeast proposes to install only two pumps in this application, leaving the third pump column for future expansion. After the 2009 draft EIS was issued, Downeast revised the Process Area Impoundment Basin to have dimensions of 24-feet-wide by 24-feet-long by 22-feet-deep.[31] The sump would have a volume of 94,793 gallons to contain a header spill with the two in-tank pumps running at full rated capacity [(4,600 gpm rated flow) x (2 in-tank pumps) x (10 minutes) = 92,000 gallons]. The Process Area Impoundment Basin would also be able to contain the 8,300 gallon HP Pump Drum, which is the largest process vessel serving the impoundment. The supplemental draft EIS using the pump rated flow neglects the potential maximum pump run-out flow rate of the in-tank pumps, which would produce a volume of 115,000 gallons [(5,750 gpm maximum flow) x (2 in-tank pumps) x (10 minutes)]. As a result, Downeast revised the Process Area Impoundment Basin depth to 27 feet deep to accommodate the maximum pump run-out flow. Any future installation of a third in-tank pump would require another application to FERC under Section 3 of the Natural Gas Act and a new siting analysis.

The Vaporizer Area Impoundment Basin would be located to the west of the vaporizers and would serve all four of the SCVs. After the 2009 draft EIS was issued, Downeast revised the Vaporizer Area Impoundment Basin to have dimensions of 20-feet-wide by 20-feet-long by 22-feet-deep.[32] The sump would have a volume of 65,828 gallons. There would be no process vessels which would drain to the Vaporizer Area Impoundment Basin. The supplemental draft EIS recognized using the failure of the 16-inch-diameter vaporizer inlet line and accounting for the pump run-out flow rate of all four proposed pumps (including the backup pump that would be installed) would yield a sizing spill volume of 75,040 gallons [(1,876 gpm maximum pump

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[31] The original design of the Process Area Impoundment Basin listed in the application was 30-feet-wide by 30-feet-long by 22-feet-deep, equating to an available capacity of 148,114 gallons. This size appeared to be based on potential flow from a third in-tank pump, even though the application only proposed two pumps.

[32] The original Vaporizer Area Impoundment Basin listed in the application was 30-feet-wide by 30 feet-long by 22-feet-deep, equating to an available capacity of 148,114 gallons.

run-out flow rate) x (4 high-pressure pumps) x (10 minutes)]. As a result, Downeast revised the Vaporizer Area Impoundment Basin depth to 26 feet deep to accommodate the larger spill.

The Transfer Area Impoundment Basin would serve the loading and recirculation lines and would have dimensions of 60-feet-wide by 60-feet-long by 24-feet-deep (this would also be equipped with internal weirs 45-feet-wide by 45-feet-long by 24-feet-deep). These dimensions yield an available capacity of 646,317 gallons. Downeast sized this impoundment basin for a full rupture of the unloading line during unloading operations. The 36-inch-diameter unloading line would have a flow rate of 61,745 gpm, equating to a sizing spill of 617,450 gallons over a 10-minute period. The Transfer Area Impoundment Basin would contain the above-mentioned spill. The Transfer Area Impoundment Basin would also be able to contain the 5,300 gallon Jetty Drum, which is largest process vessel serving the impoundment.

The spill volumes and corresponding impoundment volumes are shown in table 4.12.5-1.

TABLE 4.12.5-1

**Impoundment Area Sizing**

| Source | Spill Size (gallons) | Impoundment System | Impoundment Size (gallons) |
|---|---|---|---|
| LNG Storage Tank | 45,117,046 | Outer Tank Concrete Wall | 52,116,919 |
| In-tank pump withdrawal header | 115,000 | Process Area Impoundment Basin (S-606) | 116,337 |
| HP pump discharge line | 75,040 | Vaporization Area Impoundment Basin (S-607) | 77,797 |
| 36-inch Unloading Line | 617,450 | Transfer Area Impoundment Basin (s-608) | 646,317 |

### *Design Spills*

Design spills are used in the determination of vapor dispersion and thermal radiation exclusion zones required by Part 193. Prior to the incorporation of NFPA 59A in 2000, the design spill in Part 193 assumed the full rupture of "a single transfer pipe which has the greatest overall flow capacity" for not less than 10 minutes (old Part 193.2059(d)). With the adoption of NFPA 59A, the basis for the design spill for impounding areas serving only vaporization, process, or LNG transfer areas became the flow from any single accidental leakage source.

As neither Part 193 nor NFPA 59A (2001) defines "single accidental leakage source", FERC staff sent a letter to the DOT on April 19, 2005, requesting concurrence on proposed procedures for determining a single accidental leakage source. As described in that letter, FERC staff based the determination of the single accidental leakage source on an evaluation of all small diameter attachments to the transfer piping for instrumentation, pressure relief, recirculation, etc., and any flanges that may be used at valves or other equipment, in order to determine the largest spill rate. The DOT affirmed this approach in a May 6, 2005 response.

However, this approach did not provide any quantitative justification for the selection of the design spill to be used in Part 193 hazard & exclusion zone calculations, and a wide variety of single accidental leakage sources, ranging from packing and flange leaks to full guillotine ruptures of ship unloading lines, were proposed in applications before the FERC. To achieve a more consistent approach, we began using equipment failure rates to establish a more quantitative threshold for single accidental leakage source under Part 193. Table 4.12.5-2 provides types of failures and associated failure rates (Mniszewski, 1984; GRI, 1981; Welker, 1979; Pelto, 1984; Pelto, 1982; Mannan, 2005; RIVM, 1999; RIVM, 1992; RIVM, 1997; HSE, 2011; RIVM, 2009).

For storage tanks with over-the-top-fill and no penetrations below the liquid level, Part 193, through adopted portions of NFPA 59A (2001), defines the design spill as the largest flow from any single line that could be pumped into the impounding area with the container withdrawal pumps delivering the full-rated capacity. Based on published failure rates for LNG facilities, the rupture of a storage tank outlet line is on the order of one failure every 20,000 to 30,000 equipment-years ($6x10^{-5}$ to $3x10^{-5}$ failures per 8,760 hours of equipment operation). Because this failure rate applies to a design spill that is specified by Part 193, we believe it could be used as a threshold for determining single accidental leakage sources for impounding areas serving liquefaction process and transfer areas. Selecting a design spill based on equipment failure rates equivalent to the failure specified by Part 193 for storage tanks provides a more consistent quantitative basis for design spills. DOT concurred with this approach for Part 193 calculations.[33]

TABLE 4.12.5-2

**Equipment Failure Rates**

| Type of Failure | Failures per equipment-year |
|---|---|
| **Cryogenic Storage Tanks (General)** | |
| Rupture of Storage Tank Outlet Line | 3E-5 (criteria) |
| **Single Containment Atmospheric Storage Tanks** | |
| Catastrophic Failure of Inner Tank (Rupture) | 5E-6 per tank |
| Catastrophic Failure of Tank Roof | 1E-4 per tank |
| Release from a hole with effective diameter of 1m (~3ft) | 8E-5 per tank |
| Release from a hole with effective diameter of 0.3m (~1ft) | 2E-4 per tank |
| Release from a hole with effective diameter of 0.01m (0.4in) | 1E-4 per tank |
| **Double Containment Atmospheric Storage Tanks** | |
| Catastrophic Failure of Inner Tank (Rupture) | 5E-7 per tank |
| Catastrophic Failure of Tank Roof | 1E-4 per tank |
| Release from a hole with effective diameter of 1m (~3ft) | 1E-5 per tank |
| Release from a hole with effective diameter of 0.3m (~1ft) | 3E-5 per tank |
| Release from a hole with effective diameter of 0.01m (0.4in) | 1E-4 per tank |
| **Full Containment Atmospheric Storage Tanks** | |
| Catastrophic Failure of Inner Tank (Rupture) | 1E-8 per tank |
| Catastrophic Failure of Tank Roof | 4E-5 per tank |
| Release from a hole with effective diameter of 1m (~3ft) | 1E-6 per tank |
| Release from a hole with effective diameter of 0.3m (~1ft) | 3E-6 per tank |
| Release from a hole with effective diameter of 0.01m (0.4in) | 1E-4 per tank |
| **Process Vessels, Distillation Columns, Heat Exchangers, & Condensers** | |
| Catastrophic Failure (Rupture) | 5E-6 per vessel |
| Release from a hole with effective diameter of 0.01m (0.4in) | 1E-4 per vessel |

[33] PHMSA Interpretation: Letter to Mr. Leon A. Bowdoin, Jr., Regarding The Applicability of 49 CFR 193.2059(c) to a Hypothetical Waterfront Liquefied Natural Gas Plant. (February 28, 2012)

TABLE 4.12.5-2

**Equipment Failure Rates**

| Type of Failure | Failures per equipment-year |
| --- | --- |
| **Truck Transfer** | |
| Rupture of transfer arm | 3E-4 per transfer arm |
| Release from a hole in transfer arm with effective diameter of 10% transfer arm diameter with maximum of 50mm (2-inches) | 3E-3 per transfer arm |
| Rupture of transfer hose | 4E-2 per transfer hose |
| Release from a hole in transfer hose with effective diameter of 10% transfer hose diameter with maximum of 50mm (2-inches) | 4E-1 per transfer hose |
| **Ship Transfer** | |
| Rupture of transfer arm | 2E-5 per transfer arm |
| Release from a hole in transfer arm with effective diameter of 10% diameter with maximum of 50mm (2-inches) | 2E-4 per transfer arm |
| **Piping (General)** | |
| Rupture at Valve | 9E-6 per valve |
| Rupture at Expansion Joint | 4E-3 per expansion joint |
| Failure of Gasket | 3E-2 per gasket |
| **Piping: d< 50mm (2-inch)** | |
| Catastrophic rupture | 1E-6 per meter of piping |
| Release from hole with effective diameter of 25mm (1-inch) | 5E-6 per meter of piping |
| **Piping: 50mm (2-inch) ≤d< 149mm (6-inch)** | |
| Catastrophic rupture | 5E-7 per meter of piping |
| Release from hole with effective diameter of 25mm (1-inch) | 2E-6 per meter of piping |
| **Piping: 150mm (6-inch) ≤d< 299mm (12-inch)** | |
| Catastrophic rupture | 2E-7 per meter of piping |
| Release from hole with effective diameter of 1/3 diameter | 4E-7 per meter of piping |
| Release from hole with effective diameter of 25mm (1-inch) | 7E-7 per meter of piping |
| **Piping: 300mm (12-inch) ≤d< 499mm (20-inch)** | |
| Catastrophic rupture | 7E-8 per meter of piping |
| Release from hole with effective diameter of 1/3 diameter | 2E-7 per meter of piping |
| Release from hole with effective diameter of 10% diameter, up to 50mm (2-inches) | 4E-7 per meter of piping |
| Release from hole with effective diameter of 25mm (1-inch) | 5E-7 per meter of piping |
| **Piping: 500mm (20-inch) ≤d** | |
| Catastrophic rupture | 2E-8 per meter of piping |
| Release from hole with effective diameter of 1/3 diameter | 1E-7 per meter of piping |
| Release from hole with effective diameter of 10% diameter, up to 50mm (2-inches) | 2E-7 per meter of piping |
| Release from hole with effective diameter of 25mm (1-inch) | 4E-7 per meter of piping |

In addition, DOT requested in a letter to the FERC staff, dated August 6, 2013, that LNG facility applicants contact the Office of Pipeline Safety's Engineering and Research Division regarding the Part 193 siting requirements.[34] Specifically, DOT stated that it required a technical review of

[34] August 6, 2013 Letter from Kenneth Lee, Director of Engineering and Research Division, Office of Pipeline Safety to Terry Turpin, LNG Engineering and Compliance Branch, Office of Energy Projects. Filed in Docket Number CP07-52 on August 13, 2013. Accession Number 20130813-400

the applicant's design spill criteria for single accidental leakage sources on a case-by-case basis to determine compliance with Part 193.

In response, Downeast provided DOT with its design spill criteria and identified leakage scenarios for the proposed equipment based on the failure rate approach described above. DOT reviewed the data and methodology Downeast used to determine the design spills based on the flow from various leakage sources, including piping, containers, and equipment containing hazardous fluids. On January 30, 2014, DOT provided a letter to the FERC staff stating that DOT had no objection to Downeast's methodology for determining the single accidental leakage source for the candidate design spills to be used in establishing the Part 193 siting requirements for the proposed LNG liquefaction facilities.[35,36] The design spills produced by this method were identified in the documents reviewed by DOT and have been filed in the docket for this project. These are the same design spills described in the following sections.

DOT's conclusions on the candidate design spills used in the siting calculations required by Part 193 was based on preliminary design information which may be revised as the engineering design progresses. If Downeast's design or operation of the proposed facility differs from the details provided in the documents on which DOT based its review, then the facility may not comply with the siting requirements of Part 193. As a result, **we recommend that**:

- **<u>Prior to the construction of the final design</u>, Downeast should file with the Secretary for review and approval by the Director of OEP, certification that the final design is consistent with the information provided to DOT as described in the design spill determination letter dated January 30, 2014 (Accession Number 20140203-4005). In the event that any modifications to the design alters the candidate design spills on which the Title 49 CFR Part 193 siting analysis was based, Downeast should consult with DOT on any actions necessary to comply with Part 193.**

As design spills vary depending on the hazard (vapor dispersion, overpressure or radiant heat), the specific design spills used for the Downeast siting analysis are discussed under "Vapor Dispersion Analysis" and "Thermal Radiation Analysis" in this section.

***Vapor Dispersion Analysis***

As discussed in section 4.12.2, a large quantity of LNG spilled without ignition would form a flammable vapor cloud that would travel with the prevailing wind until it either dispersed below the flammable limit or encountered an ignition source. In order to address this hazard, 49 CFR § 193.2059 requires each LNG container and LNG transfer system to have a dispersion exclusion

[35] January 30, 2014 Letter "Re: Downeast LNG Project, FERC Docket No. CP07-52-000 and CP07-53-000, Design Spill Determination" from Kenneth Lee to Lauren H. O'Donnell. Filed in Docket Number CP07-52 on February 3, 2014. Accession Number 20140203-4005

[36] PHMSA based this decision on the following documents: (1) Downeast Response to FERC Data Request, Accession Number 20091029-5075; (2) Downeast Response to FERC Data Request, Accession Number 20121012-5103; (3) Downeast Response to FERC Data Request, Accession Number 20121113-5487; (4) Downeast Response to FERC Data Request, Accession Number 20120523-5172; (5) FERC Supplemental Draft Environmental Impact Statement (DEIS), Accession Number 20130328-4001; (6) Downeast Response to the Supplemental DEIS, Accession Number 20130523-5131; (7) Downeast Response to FERC Data Request, Accession Numbers 20130927-5214 & 5215; and (8) Downeast Response to PHMSA Data Request, Accession Numbers 20140130-5363 and 20140130-5364

zone in accordance with sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001). Taken together, Part 193 and NFPA 59A (2001) require that flammable vapors either from an LNG tank impoundment or a single accidental leakage source do not extend beyond a facility property line that can be built upon. This is the Part 193 standard that we used in analyzing the siting of the proposed Project.

Title 49 CFR §193.2059 requires that dispersion distances be calculated for a 2.5 percent average gas concentration (one-half the LFL of LNG vapor) under meteorological conditions which result in the longest downwind distances at least 90 percent of the time. Alternatively, maximum downwind distances may be estimated for stability Class F, a wind speed of 4.5 mph, 50 percent relative humidity, and the average regional temperature.

The regulations in Part 193 specifically approve the use of two models for performing these dispersion calculations, DEGADIS and FEM3A. The use of alternative models is also allowed, but must be specifically approved by the DOT. Although Part 193 does not require the use of a particular source term model, modeling of the spill and resulting vapor production is necessary prior to the use of vapor dispersion models. In the past, applicants have typically used the SOURCE5 program to model the vapor production from an LNG spill.

Based on requests for clarification on the source term requirements of Part 193, the DOT issued two formal interpretations in July of 2010 regarding the regulations under 49 CFR 193.[37] In these interpretations, the DOT stated that:

- SOURCE5 could no longer be used to determine the vapor gas exclusion zone for compliance with § 193.2059 unless the deficiencies identified in the Fire Protection Research Foundation's reports "Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities Research Project (April 2007)" and "LNG Source Term Models for Hazard Analysis: A Review of the State-of-the-Art and an Approach to Model Assessment (March 2009)" had been addressed;

- source term models must have a credible scientific basis and must not ignore phenomena which can influence the discharge, vaporization, and conveyance of LNG; and

- an alternative source term model proposed by Downeast was suitable for siting impoundments, but the effects of flashing and jetting (and any other phenomena having a similar influence on the discharge, vaporization, or conveyance of LNG) must be considered in order to comply with §193.2059.

As a result of these interpretations, alternative dispersion models became necessary in order to examine the effects of jetting, flashing and conveyance of LNG for exclusion zone calculations. In August 2010, the DOT issued Advisory Bulletin ADB-10-07 to provide guidance on obtaining approval of alternative vapor-gas dispersion models under Subpart B of 49 CFR 193. In October 2011, two dispersion models were approved by DOT for use in vapor dispersion exclusion zone

[37] PHMSA Interpretation "Re: Request for Written Interpretation on the Applicability of 49 CFR 193 to Proposed Waterfront Liquefied Natural Gas Plant in the City of Fall River, Massachusetts" (July 7, 2010) and PHMSA Interpretation "Re: Request for Written Interpretation on the Applicability of 49 CFR 193 to Proposed LNG Import Terminal in Robbinston, Maine" (July 16, 2010).

calculations: PHAST-UDM Version 6.6 and Version 6.7 (submitted by Det Norske Veritas) and FLACS Version 9.1 Release 2 (submitted by GexCon).

On May 23, 2012, and October 12, 2012, as supplemented on October 26 and November 13, 2012, Downeast submitted analyses to address the vapor dispersion analysis requirements of Part 193. PHAST 6.7 and FLACS 9.1, with their built-in source term models, were used to calculate dispersion distances. As the 2011 DOT approvals of the alternative dispersion models did not address source term models, we consulted with the DOT on Downeast's submitted PHAST and FLACS source term modeling. Based on our consultation with DOT staff, we conclude that the use of the PHAST flashing and jetting source term models and the use of the FLACS flashing / jetting / pool spread and vaporization source term models are suitable and comply with the siting requirements of Part 193 for this project. As this determination must be made on a project specific basis, this conclusion would need to be revisited for future applications of these source models.

As discussed under "Design Spills" in section 4.12.5, failure scenarios must be selected as the basis for the Part 193 dispersion analyses. Process conditions at the failure location would affect the resulting vapor dispersion distances. In determining the spill conditions for these leakage sources, process flow diagrams for the proposed design, used in conjunction with the heat and material balance information (i.e., flow, temperature, and pressure), can be used to estimate the flow rates and process conditions at the location of the spill. In general, higher flow rates would result in larger spills and longer dispersion distances; higher temperatures would result in higher rates of flashing; and higher pressures would result in higher rates of jetting and aerosol formation. Therefore, two scenarios may be considered for each design spill:

- The pressure in the line is assumed to be maintained by pumps and/or hydrostatic head to produce the highest rate of flashing and jetting (i.e. flashing and jetting scenario); and
- The pressure in the line is assumed to be depressurized by the breach and/or emergency shutdowns to produce the highest rate of liquid flow within a curbed, trenched, or impounded area (i.e. liquid scenario).

Alternatively, a single scenario for each design spill could be selected if adequately supported with an assessment of the depressurization calculations and/or an analysis of process instrumentation and shutdown logic acceptable to DOT.

In addition, the location and orientation of the leakage source must be considered. The closer a leakage source is to the property line, the higher the likelihood that the vapor cloud would extend off-site. As most flashing and jetting scenarios would not have appreciable liquid rainout and accumulation, the siting of impoundment systems would be driven by liquid scenarios, while siting of remaining portions of the plant would be driven by flashing and jetting scenarios.

Downeast reviewed 266 single accidental leakage sources for the liquid scenarios and for the flashing and jetting scenarios. Downeast used the following conditions, corresponding to 49 CFR 193.2059, for the vapor dispersion calculations: ambient temperature of 69°F, relative humidity of 50 percent, wind speed of 4.5 mph in various directions, atmospheric stability class of F and a ground surface roughness of 0.03 meters. In addition, a sensitivity analysis to the wind speed and direction was provided to demonstrate the longest predicted downwind dispersion distance in accordance with the PHAST and FLACS Final Decisions. A sensitivity analysis to a ground surface roughness of 0.01 meters was also provided for spills over water.

Downeast accounted for the facility geometry, including the impoundment and trench geometry details as established by available plant layout drawings. Including the plant geometry accounts for any on-site wind channeling that could occur and allows for inclusion of mitigation measures, such as vapor fences. The releases were initiated after sufficient time had passed in the model simulations to allow the wind profile to stabilize from effects due to the presence of buildings and other on-site obstructions.

In order to address the highest rate of LNG liquid flow (i.e. liquid scenario) into the Process Area Impoundment Basin, and in accordance with table 2.2.3.5 of NFPA 59A (2001) for storage tanks with over-the-top fill and no penetrations below the liquid level, Downeast specified the design spill as a complete rupture of the 20-inch-diameter discharge header with both in-tank pumps running at full rated capacity [(4,600 gpm rated flow) x (2 in-tank pumps) = 9,200 gpm]. In order to address the highest rate of LNG flashing and jetting from piping in the Process Area, Downeast submitted a release through a 2-inch-diameter hole in this piping, calculated to be 785 gpm. However, in performing the vapor dispersion modeling for flashing and jetting scenarios, Downeast actually used a larger spill from a 6-inch-diameter release of approximately 7,775 gpm from LNG piping in the tank.

In order to address the highest rate of LNG liquid flow (i.e. liquid scenario) into the Vaporizer Area Impoundment Basin, Downeast specified the design spill as a complete rupture of the 6-inch-diameter vaporizer-inlet line, resulting in a 3,448 gpm spill rate. In order to address the highest rate of LNG flashing and jetting from piping in the Process Area, Downeast submitted a release through a 1-inch-diameter hole in the high pressure pump area, calculated to be 1,127 gpm. However, in performing the vapor dispersion modeling for flashing and jetting scenarios, Downeast actually used a larger 3-inch-diameter release of approximately 1,380 gpm from LNG piping in the high pressure pump area.

In order to address the highest rate of LNG liquid flow (i.e. liquid scenario) into the Transfer Area Impoundment Basin, Downeast specified the design spill as a hole equivalent to 1/3 diameter of the 36-inch-diameter transfer line, resulting in a 32,330 gpm spill rate. In order to minimize jetting effects, Downeast proposes to install a 6-foot high vapor fence that runs along each side of the transfer line. With the vapor fences, a hole sensitivity analysis showed the highest amount of vapor would be produced by the 12-inch hole along the transfer line. In addition, Downeast considered a 4-inch-diameter release from LNG piping in the dock area where there would not be any vapor fences resulting in an orifice flow rate of approximately 3,450 gpm. Table 4.12.5-3 summarizes the design spills specified by Downeast.

| TABLE 4.12.5-3<br>**LNG Design Spills** | | | | |
|---|---|---|---|---|
| **Scenario** | **Release location** | **Equivalent Hole Size** | **Total Flow Rate (gpm)** | **Liquid Fraction (%)** |
| 1 | Process Area | 20-inch | 9,200 | 100 |
| 2 | Process Area | 6-inch | 7,775 | 0 |
| 3 | Vaporizer Area | 6-inch | 3,448 | 100 |
| 4 | Vaporizer Area | 3-inch | 1,380 | 0 |
| 5 | Transfer Line | 12-inch | 32,330 | 100 |
| 6 | Transfer Line | 12-inch | 32,330 | 95 |
| 7 | Dock Area | 4-inch | 3,450 | 0 |

Downeast's simulations indicated the need for a series of 20-30 foot high vapor fences throughout the onshore plant and a 6 foot high vapor fence along each side of the transfer line. Downeast proposes a fence made of impermeable Galvalume panels fastened to galvanized beams and posts to act as a vapor barrier to prevent the LNG vapor from extending beyond the western, northern, and southern property lines. There would be no vapor fence along the eastern property line adjacent to the waterway. The vapor fences are shown in Figure 4.12.5-1.

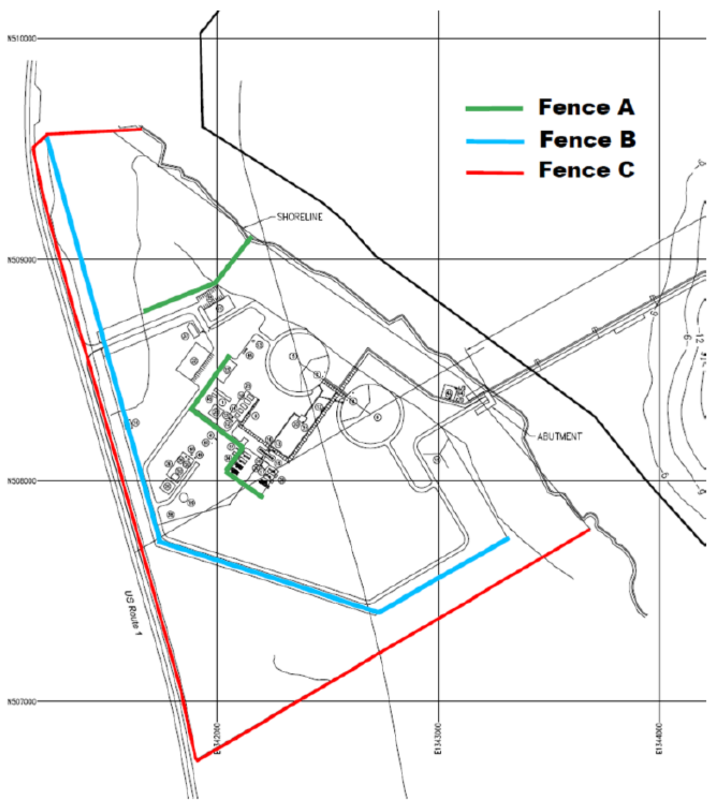



**Figure 4.12.5-1 Vapor Fences Proposed at Downeast Onshore Facilities**
**Fence A would be 20 feet high, Fence B would be 25 feet high, and Fence C would be 30 feet high.**

In its filings, Downeast presented that the ½ LFL vapor cloud for flashing and jetting cases would remain within the Downeast LNG property or would not extend beyond the property line to the west, north or south considering installation of the vapor barriers. Downeast stated that the vapor barriers would be routinely inspected by personnel and repaired as necessary. In addition, security patrols would observe the vapor barriers during their regular rounds and report any observed damage. In order to ensure that the vapor barriers are maintained throughout the life of the facility, **we recommend that:**

- **<u>Prior to construction of the final design,</u> Downeast should file with the Secretary for review and written approval by the Director of OEP, procedures to maintain and inspect the vapor barriers provided to meet the siting provisions of 49 CFR 193.2059. This information should be filed a minimum of 30 days before approval to proceed is requested.**

The flammable vapor dispersion results are consolidated into figure 4.12.5-2. The FLACS simulations showed that, due to the proposed vapor fences within the plant, none of the design spills would result in the ½ LFL vapor dispersion extending over a property line that could be built upon. As a result, we conclude that the siting of the proposed facility would not have a significant impact on public safety. If the facility is constructed and operated, compliance with the requirements of 49 CFR 193 would be addressed as part of DOT's inspection and enforcement program.


Downeast dispersion results

**Figure 4.12.5-2 Vapor Dispersion Exclusion Zones**

We received comments on Downeast's vapor dispersion exclusion zones extending beyond the shoreline along the eastern property line and over public access routes to intertidal recreation and study areas. The commentor stated that, as Downeast would have no ability to control public access in these areas, the exclusion zones would be in violation of Part 193. DOT has indicated an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable unless the body of water contains a dock or pier that is not controlled by the LNG plant or if another entity could build a building or members of the public could assemble. During the development of the supplemental draft EIS, we raised the issue with the vapor dispersion exclusion zones extending past the property line onto the waterway and intertidal zone with DOT. DOT staff informed FERC staff that the vapor dispersion exclusion zones onto the waterway and intertidal zone would not violate the Part 193 exclusion zone requirements.

***Overpressure Considerations***

As discussed in section 4.12.2, the propensity of a vapor cloud to detonate or produce damaging overpressures is influenced by the ignition source, reactivity of the material, the level of confinement and congestion surrounding and within the vapor cloud, and the flame travel distance. It is possible that the prevailing wind direction may cause the vapor cloud to travel into a partially confined or congested area.

As adopted by Part 193, Section 2.1.1 of NFPA 59A (2001) requires an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility be considered. As discussed under "Overpressures" in section 4.12.2, unconfined LNG vapor clouds would not be expected to produce damaging overpressures. The presence of heavier hydrocarbons influences the propensity for a detonation or deflagration with damaging overpressures. Product with greater amounts of heavier hydrocarbons is more sensitive to detonation. LNG facilities have typically imported LNG with methane concentrations ranging from 89 percent to 96 percent with occasional imports as low as 86 percent. The Downeast LNG import facility would be designed to receive LNG with methane concentrations as low as 87 percent. These compositions are not in the range shown to exhibit overpressures and flame speeds associated with high-order explosions and detonations.

The Coast Guard studies referenced under "Overpressures" in section 4.12.2 indicated overpressures of 4 bar and flame speeds of 35 m/s (meters per second) were produced from vapor clouds of 86 percent to 96 percent methane in near stoichiometric proportions using exploding charges as the ignition source. The 4 bar overpressure was the same overpressure produced during the calibration test involving exploding the charge ignition source alone, so it remains unclear that the overpressure was attributable to the vapor deflagration. However, unconfined methane vapor clouds ignited with low energy ignition sources have been shown to produce flame speeds ranging from 5.2 to 7.3 m/s, which is much less than the flame speeds associated with explosions or detonations.

Additional tests were conducted to study the influence of confinement and congestion on the propensity of a vapor cloud to detonate or produce damaging overpressures. The tests used obstacles to create a partially confined and turbulent scenario, but found that flame speeds developed for methane were not significantly higher than the unconfined case and were not in the range associated with detonations.

For unconfined and congested vapor clouds, we still evaluated the proposed plant design and found that most areas of confinement and congestion would be within the process areas of the plant. These areas would be less likely to ignite a vapor cloud due to required safety measures, such as the electrical area classification for Class 1, Division 1 or 2. However these areas are not without risk, therefore, despite these safety measures, we used the BST methodology, recently updated based on the work of Pierorazio, Thomas, Baker, and Ketchum in 2005, in order to investigate the effects of such a vapor cloud migrating into a congested area.

Based on our analysis of the proposed layout and pipe rack cross-sections, the process areas would have volume and area blockage ratios consistent with a low congestion area and would allow for expansion consistent with 2.5D confinement (i.e. pipe rack where pipes are almost touching). The primary flammable substances in the process area would be methane. Using the revised BST methodology, the vapor cloud explosion overpressures would not reach 1 psi, a value used in consequence analyses by FERC staff and required under other federal agency regulations, such as Title 40 CFR Part 68.22, reflective of damage to light wooden framed structures and shattering of glass.

After the 2009 draft EIS was issued, we received comments on whether the vapor fences would cause a confinement and potentially result in damaging overpressures from an ignited vapor cloud. The 6-foot vapor fences along the dock are separated by nearly 18 feet and the 30-foot and 25-foot tall vapor fences are nearly 80 feet apart where the two run parallel and closest to each other at the western property line. These separation distances are more than adequate enough to prevent any pressure build-up if there is a lack of congestion between the vapor fences. However, Downeast has indicated that approximately 33 acres of forested area, including a 250 treeline buffer, would be maintained along the shoreline and within the plant boundaries and vapor fences. These trees were not accounted for in the vapor dispersion hazard analyses and were not considered in any vapor cloud explosion hazard analyses. Although the presence of the trees should reduce the vapor dispersion distances, the congestion from the trees could cause a vapor cloud explosion hazard depending on the level of congestion. Therefore**, we recommend that:**

- **<u>Prior to initial site preparation</u>, Downeast should file with the Secretary for review and written approval by the Director of OEP, certification that all trees would be removed from the area between the vapor fences and the shoreline. Alternatively, Downeast may demonstrate that the spacing of the trees, and any vegetation management plan, would prevent congested areas that could produce offsite overpressures above 1 psi.**

Given the LNG compositions which would be handled onsite, potential ignition sources, and the expected vapor dispersion characteristics, damaging overpressures would not be expected to occur from ignition of an unconfined vapor cloud.

Ignition of a confined vapor cloud could also result in higher overpressures. In order to prevent such an occurrence, buildings are typically located away from process areas containing flammable materials. Furthermore, as required by our recommendation in section 4.12.3, Downeast would need to demonstrate that all areas are adequately covered by hazard detection devices. A preliminary evaluation of the Downeast facility indicates the only enclosed buildings within the facility would be the administrative building, control room building, and electrical switchgear building. In order to reduce the likelihood of flammable vapors dispersing into these buildings, Downeast proposes to pressurize these buildings, elevate the heating, ventilation, and air conditioning (HVAC) intakes above the maximum height of any modeled flammable vapor cloud, and install a flammable gas detector at the HVAC intake to initiate an alarm and shutdown of the HVAC blower upon detection of 20 percent LFL gas concentrations. We believe these measures provide sufficient protection and that the potential for overpressures from confined vapor clouds would be negligible.

***Thermal Radiation Analysis***

As discussed in section 4.12.2, if flammable vapors are ignited, the resulting pool fire would cause high levels of thermal radiation (i.e., heat from a fire). In order to address heat from pool fires, 49 CFR § 193.2057 specifies hazard endpoints in terms of flux levels for spills into LNG storage tank containment and spills into impoundments for process or transfer areas. For any distance from a pool fire, a flux level which expresses how much thermal radiation would be received at that point can be calculated. Each LNG container and LNG transfer system is required to have a thermal exclusion zone in accordance with Section 2.2.3.2 of NFPA 59A (2001). Together, Part 193 and NFPA 59A (2001) specify different hazard endpoints for spills into LNG storage tank containment and spills into impoundments for process or transfer areas. For LNG storage tank spills, there are three radiant heat flux levels which must be considered:

- 1,600 British thermal units per square foot per hour (Btu/ft$^2$-hr) - This level can extend beyond the facility's property line that can be built upon but cannot include areas that, at the time of facility siting, are used for outdoor assembly by groups of 50 or more persons;
- 3,000 Btu/ft$^2$-hr - This level can extend beyond the facility's property line that can be built upon but cannot include areas that, at the time of facility siting, contain assembly, educational, health care, detention or residential buildings or structures; and
- 10,000 Btu/ft$^2$-hr - This level cannot extend beyond the facility's property line that can be built upon.

The requirements for smaller spills from process or transfer areas are more stringent. For these impoundments, the 1,600 Btu/ft$^2$-hr flux level cannot extend beyond the facility's property line that can be built upon.

Part 193 requires the use of the LNGFIRE3 computer program model developed by the Gas Research Institute to determine the extent of the thermal radiation distances. Part 193 stipulates that the wind speed, ambient temperature, and relative humidity that produce the maximum exclusion distances must be used, except for conditions that occur less than 5 percent of the time based on recorded data for the area.

For its analysis, Downeast calculated thermal radiation distances for the 1,600-, 3,000-, and 10,000-Btu/ft$^2$-hr incident radiant heat levels for the LNG storage tank using the outer tank's concrete wall diameter (254 feet) as the pool diameter. The flame height was set equal to the top of the concrete wall (142.75 feet). In addition, Downeast calculated thermal radiation distances using LNGFIRE3 for the 1,600-Btu/ft$^2$-hr incident radiant heat levels centered on the Process Area Impoundment Basin, the Vaporizer Area Impoundment Basin, and the Transfer Area Impoundment Basin. Downeast selected the following ambient conditions to produce the maximum exclusion distances: wind speeds of 8-16 mph, ambient temperature of 15°F, and 47 percent relative humidity.

For the storage tanks, target heights were set at 0 feet and 52 feet to reflect the minimum and maximum ground level elevation changes from to an offsite area affected by the radiant heat. The elevated target height for the storage tank provides higher thermal radiation intensities as the target would be closer to the elevated fire. For the impoundments, target heights were set at 0 feet as the ground level elevation changes were minimal from the impoundments to offsite areas affected by the radiant heat. The resulting maximum thermal radiation distances are shown in table 4.12.5-4, figure 4.12.5-3 and figure 4.12.5-4.

TABLE 4.12.5-4

**Thermal Radiation Exclusion Zones for Impoundment Basins**

| Flux Level ($Btu/ft^2$-hr ) | Full Containment Tank Outer Containment (ft)* | Process Area Impoundment Basin (ft)* | Vaporizer Area Impoundment Basin (ft)* | Transfer Area Impoundment Basin (ft)* |
|---|---|---|---|---|
| 10,000 | 429 | 58 | 38 | 194 |
| 3,000 | 741 | 113 | 96 | 268 |
| 1,600 | 950 | 137 | 115 | 322 |

*from center of impoundment

As shown in figure 4.12.5-3, both the 10,000-, and 3,000-$Btu/ft^2$-hr heat flux for the LNG storage tanks would remain within the facility property lines. The 1,600 $Btu/ft^2$-hr flux level would extend beyond the facility property line onto US Route 1. DOT has indicated that an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable. As a result, we conclude that the siting of the proposed LNG storage tanks would not have a significant impact on public safety. If the facility is constructed and operated, compliance with the requirements of 49 CFR 193 would be addressed as part of DOT's inspection and enforcement program.

As shown in figure 4.12.5-4, the 1,600 $Btu/ft^2$-hr heat flux for the Process Area Impoundment Basin and the Vaporizer Area Impoundment Basin would remain within the facility property lines. The 1,600 $Btu/ft^2$-hr heat flux for the Transfer Area Impoundment Basin would extend beyond the facility property line over portions of the shoreline and waterway. As indicated by DOT staff, an exclusion zone that extends past a property line into a navigable body of water or onto a public road is typically acceptable unless the body of water contains a dock or pier that is not controlled by the LNG plant or if another entity could build a building or members of the public could assemble. Accordingly, we consulted DOT on the thermal radiation exclusion zones extending past the property line onto the waterway and intertidal zone where comments indicated possible areas of public access routes to recreation and study areas. During the development of the supplemental draft EIS, DOT staff informed FERC staff that the thermal radiation exclusion zones onto the waterway and intertidal zone would not violate their exclusion zone requirements. As a result, we conclude that the siting of these impoundments would not have a significant impact on public safety.

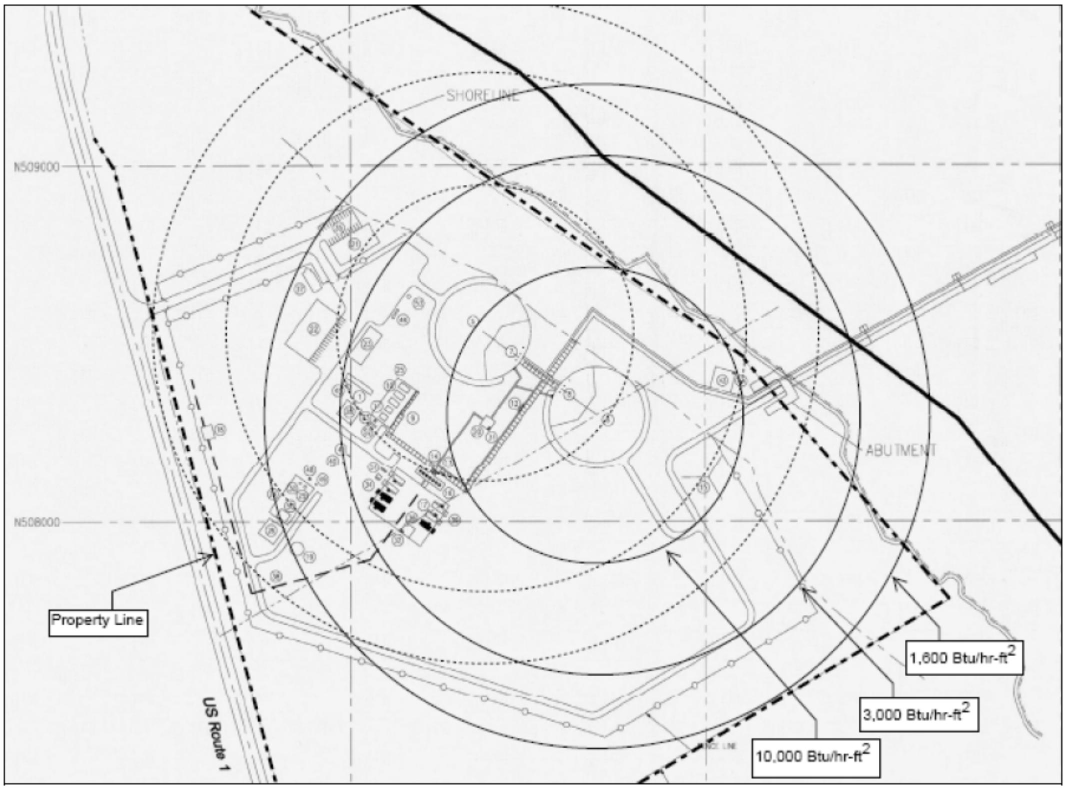



**Figure 4.12.5-3 Thermal Radiation Exclusion Zones for Storage Tanks**

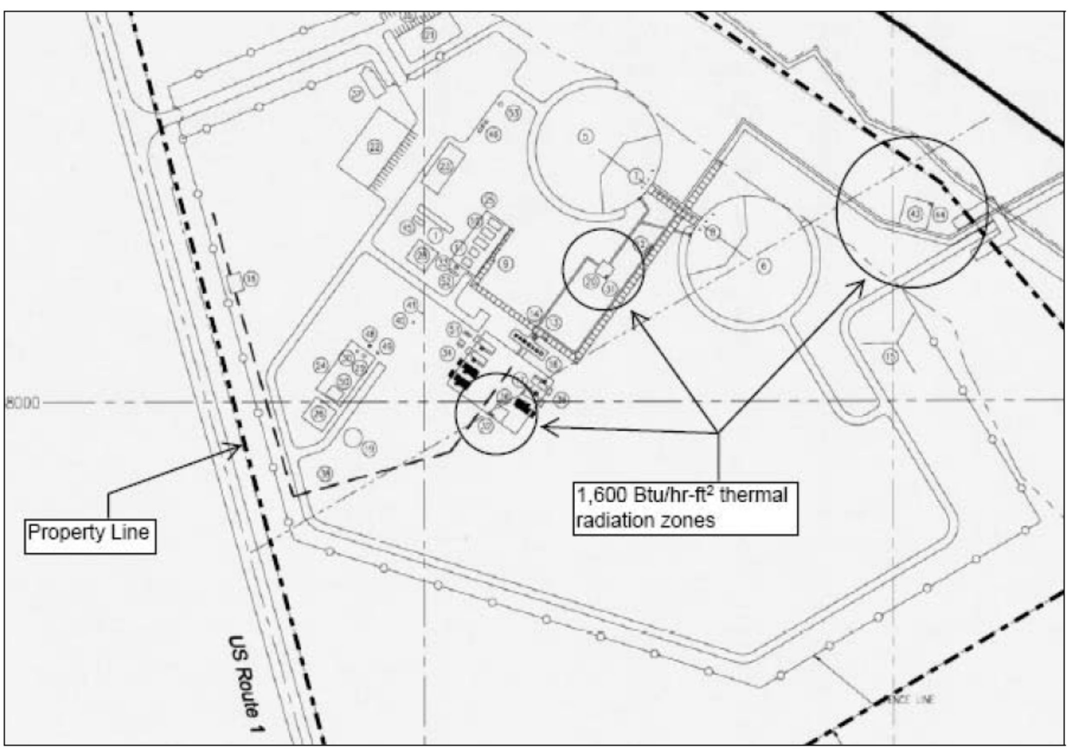



**Figure 4.12.5-4 Thermal Radiation Exclusion Zones for Impoundment Basins**

The proposed layout of the facility would also meet the NFPA 59A (2001) separation requirements of a distance equal to 0.7 times the tank diameter between the storage tank and the property line (178 feet for the tank design under consideration). However, the 10,000 Btu/ft$^2$-hr incident heat flux for the LNG storage tanks would extend over occupied buildings, such as the main control building, administrative building, and maintenance building, and over equipment that is critical to the safe shutdown and operation of emergency equipment, such as the power distribution building transformers and emergency generator. In addition, the 3,000 Btu/ft$^2$-hr incident heat flux for the Vaporizer Area Impoundment Basin would extend over the vaporizers, high pressure pumps, and associated equipment. Although there are no provisions within Part 193 or NFPA 59A (2001) which would prohibit this layout, we do not consider this to be appropriate design practice. As a result, **we recommend:**

- **<u>Prior to construction of the final design,</u> Downeast should file the following information:**

  **a. an evaluation that justifies the location of occupied buildings, including the main control building, administration building, and maintenance building, or a final design that relocates the occupied buildings or storage tank, so that the radiation from a storage tank roof top fire would be less than 10,000 Btu/ft$^2$-hr at occupied buildings.**

  **b. an evaluation that justifies the location of equipment that is critical to the safe shutdown and operation of emergency equipment, including the power distribution building transformers and emergency generator, or a final design that relocates the equipment or storage tank, so that the radiation from a storage tank roof top fire would be less than 10,000 Btu/ft$^2$-hr at the these locations.**

  **c. an evaluation that justifies the location of the vaporizers, high pressure pumps, and associated equipment, or a final design that relocates the equipment or impoundment, so that the radiation from a fire in the vaporizer spill impoundment would be less than 3,000 Btu/ft$^2$-hr at the vaporizer and high pressure pump equipment.**

After the 2009 draft EIS was issued, we received comments on the suitability of LNGFIRE3 in light of research conducted by Sandia National Laboratories (Sandia). In 2007, the DOE contracted Sandia to develop information for assessing the potential impacts associated with large LNG spills on water. The results of this study were released by DOE in the report "Liquefied Natural Gas Safety Research Report to Congress," dated May 2012. Using data gathered from these tests and earlier methane gas burner tests, Sandia developed recommendations on parameters, including mass burning rate, pool fire flame height, surface emissive power, and atmospheric transmissivity, appropriate for use in solid flame models for pool fires over water. We examined the effect of altering the LNGFIRE3 model to incorporate Sandia's recommendations regarding LNG pool fire modeling over water and on data provided by the largest LNG pool fire tests on land (Gaz de France Montoir tests) or water (Phoenix tests).[38] Our conclusions were that LNGFIRE3, as currently prescribed by 49 CFR 193, is

[38] "Recommended Parameters for Solid Flame Models for Land Based Liquefied Natural Gas Spills," Issued January 23, 2013 in Docket AD13-4-000 (eLibrary Accession Number: 20130123-4002).

appropriate for modeling thermal radiation from LNG pool fires on land and is suitable for use in siting on-shore LNG facilities.

We also received comments that LNGFIRE3 has not been verified or validated for use for tank top fires and therefore is not fit for purpose to use for siting Downeast. LNGFIRE3 has been verified and validated for relevant LNG pool fires, including the largest pool fires on land conducted to date. LNGFIRE3 is a semi-empirical model that is based on an assumed cylindrical fire shape and constant surface emissive power that utilizes a correlation for flame height based on flame diameter and burning characteristics. This is a common and well proven methodology. LNGFIRE3 also takes into account flame tilt and drag from wind effects. The correlations are based on LNG pool fire data up to 35 meters in diameter, which is typically in the range of plant impoundments, and is the largest published LNG pool fire test conducted on land. The largest published pool fire that would be within the range of a tank top fire is an 80-meter-diameter jet fuel fire conducted by Japan. However, this data is not pertinent or appropriate to use as jet fuel has very different burning characteristics, such as smoke generation. The recent Sandia large LNG pool fire tests are in the same range size and, while the results are not directly comparable for evaluating LNG pool fire models on land, the results show important trends in LNG pool fires. Although there have not been any LNG tank top fire tests to validate any LNG pool fire model, there has been an abundance of LNG and other test data that generally indicate that the semi-empirical relationships are conservative and provide confidence in the LNGFIRE3 results.

Commentors also suggested that more advanced CFD models may be more appropriate to evaluate tank top fires and knock on effects. While CFD models would be able to account for additional physical phenomenom, including obstructions that can absorb the radiant heat emitted by the fire, these models also contain assumptions that can limit their applicability and would require an evaluation before they could be claimed to be more accurate or appropriate to use than LNGFIRE3. In addition, the use of more advanced models may not necessarily be more conservative, especially as distances from the fire are increased.

Such models are also generally more dependent on user input and may be manipulated to provide a desired outcome. As discussed in a recent paper, the publically available Fire Dynamic Simulator (FDS), developed by that National Institute of Standards and Technology (NIST) is limited in its ability to model smoke generation and relies on semi-empirical relationships and user-specified input to its sub-model to determine the amount of smoke generated. This allows for the user to manipulate the soot production in the results, which can greatly affect the radiant heat levels predicted. Moreover, FDS, including the soot production levels and other variables, has not yet been subjected to an evaluation, including scientific assessment, verification or validation, for any LNG pool fire scenarios. As a result, we would have less confidence in it than in the LNGFIRE3 results at this point.

Commentors also questioned the effect of higher wind speeds on flame tilt and flame drag at higher elevations. As part of our evaluation of LNGFIRE3, we examined the effect of higher wind speeds for fires at higher elevations (e.g. storage tank roof top fires). Accounting for these effects would result in a less than 3 percent increase to the 1,600 Btu/ft$^2$-hr zone, which is well within the uncertainty of the model predictions and is not significant enough to invalidate the thermal radiation modeling results.

Commentors raised further concerns on the structural integrity of storage tanks during a storage tank fire. Assuming the storage tank outer containment progressively failed as the fire burned (similar to fires in metal storage tanks), there would be a less than 2 percent increase to the 1,600 Btu/ft$^2$-hr zone, which is well within the uncertainty of the model predictions and is not significant enough to invalidate the thermal radiation modeling results.

We also received comments that there does not exist a definite and absolute value of safe exposure. Although there are differences many regulatory and standards bodies, the majority of regulations and codes, including those by DOT, EPA, and Canadian Standards Association (CSA), specify 1,600 Btu/ft$^2$-hr (5 kW/m$^2$) as a safe limit. Other international regulations also use values at or near 5 kW/m$^2$ as a safe limit. The use of 1,600 Btu/ft$^2$-hr (5 kW/m$^2$) was re-affirmed for use at U.S. regulated facilities by the DOT in 2010. [39]

#### 4.12.6 Facility Security

Title 49, CFR, Part 193, Subpart J – Security, specifies security requirements for the onshore component of LNG facilities. This subpart includes requirements for conducting security inspections and patrols, liaison with local law enforcement officials, design and construction of protective enclosures, lighting, monitoring, alternative power sources, and warning signs. Security at the facility would be provided by both active and passive systems. The entire site would be surrounded by a protective enclosure (i.e., a fence) with sufficient strength to deter unauthorized access. The enclosure would be illuminated with not less than 2.2 lux between sunset and sunrise. Intrusion detection systems and day/night camera coverage would identify unauthorized access. A separate security staff would conduct periodic patrols of the plant, and screen visitors and contractors. The security staff may also assist in maintaining security of the marine terminal during cargo unloading.

In addition to the requirements of Part 193, there are also requirements for maintaining security of a marine terminal contained in Coast Guard regulations. Title 33, CFR, Part 105, as authorized by the Maritime Transportation Security Act (MTSA) of 2002, requires all terminal owners and operators to submit a Facility Security Assessment and a Facility Security Plan to the Coast Guard for review and approval. Some of the responsibilities of the applicant include, but are not limited to:

- designating a Facility Security Officer with a general knowledge of current security threats and patterns, risk assessment methodology, and the responsibility for implementing the Facility Security Assessment and Facility Security Plan and performing an annual audit for the life of the project;
- conducting a Facility Security Assessment to identify site vulnerabilities, possible security threats and consequences of an attack, and facility protective measures;
- developing a Facility Security Plan based on the Facility Security Assessment, with procedures for: responding to transportation security incidents; notification and coordination with local, state, and federal authorities; prevention of unauthorized access;

[39] PHMSA Interpretation "Re: Request for Written Interpretation on the Applicability of 49 CFR 193 to Proposed Waterfront Liquefied Natural Gas Plant in the City of Fall River, Massachusetts" (July 7, 2010).

measures and equipment to prevent or deter dangerous substances and devices; training; and evacuation;

- implementing scalable security measures to provide increasing levels of security at increasing maritime security levels for facility access control, restricted areas, cargo handling, vessel stores and bunkers, and monitoring;
- ensuring the Transportation Worker Identification Credential program is properly implemented; and
- reporting all breaches of security and security incidents to the National Response Center.

If this project is constructed, 33 CFR 105 would require Downeast to submit a Facility Security Plan to the Coast Guard for review and approval before commencement of operations.

The LNG carriers which would deliver LNG to the proposed facility would also need to comply with various U.S. and international security requirements. The International Maritime Organization (IMO) adopted the *International Ship and Port Facility Security Code* (ISPS Code) in 2003. The ISPS Code requires both ships and ports to conduct vulnerability assessments and to develop security plans. The purpose of the code is to prevent and suppress terrorism against ships; improve security aboard ships and ashore; and reduce the risk to passengers, crew, and port personnel on board ships and in port areas. All LNG vessels, as well as other cargo vessels 500 gross tons and larger, and ports servicing those regulated vessels, must adhere to the IMO standards. Some of the IMO requirements for ships are as follows:

- ships must develop security plans and have a Vessel Security Officer;
- ships must have a ship security alert system. These alarms transmit ship-to-shore security alerts identifying the ship, its location, and indication that the security of the ship is under threat or has been compromised;
- ships must have a comprehensive security plan for international port facilities, focusing on areas having direct contact with ships; and
- ships may have equipment onboard to help maintain or enhance the physical security of the ship.

In 2002, the MTSA was enacted by the U.S. Congress and aligned domestic regulations with the maritime security standards of the ISPS Code and the *International Convention for the Safety of Life at Sea* (SOLAS). The resulting Coast Guard regulations, contained in 33 CFR 104, require vessels to conduct vulnerability assessments and develop corresponding security plans. All LNG carriers servicing the facility would have to comply with the MTSA requirements and associated regulations while in U.S. waters.

### 4.12.7 LNG Carriers

Since 1959, ships have transported LNG without a major release of cargo or a major accident involving an LNG vessel. There are more than 370 LNG carriers in operation routinely transporting LNG between more than 100 import/export terminals currently in operation worldwide. Since U.S. LNG terminals first began operating under FERC jurisdiction in the 1970s, there have been more than 2,600 individual LNG ship arrivals at terminals in the U.S.

For the past 40 years, LNG shipping operations have been safely conducted in U.S. ports and waterways.

#### 4.12.7.1 Design and Operating Requirements

The LNG carriers used to import and export LNG to and from the United States would be constructed and operated in accordance with the IMO's *Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk*, the SOLAS, and 46 CFR 154, which contains the United States safety standards for vessels carrying liquefied natural gas in bulk.

As required by the IMO's conventions and design standards, hold spaces and insulation areas on an LNG carrier must be equipped with gas detection and low temperature alarms. These devices monitor for leaks of LNG into the insulation between primary and secondary LNG cargo tank barriers. In addition, hazard detection systems must also be provided to monitor the hull structure adjacent to the cargo tank, compressor rooms, motor rooms, cargo control rooms, enclosed spaces in the cargo area, specific ventilation hoods and gas ducts, and air locks.

In 1993, amendments to the IMO's *Code for the Construction and Equipment of Ships Carrying Dangerous Chemicals in Bulk* required all vessels to have monitoring equipment with an alarm facility which is activated by detection of over-pressure or under-pressure conditions within a cargo tank. In addition, cargo tanks must be heavily instrumented, with gas detection equipment in the hold and inter-barrier spaces, temperature sensors, and pressure gauges. LNG carriers are to be equipped with a firewater system with the ability to supply at least two jets of water to any part of the deck in the cargo area and parts of the cargo containment and tank covers above-deck. A water spray system is also available for cooling, fire prevention, and crew protection in specific areas. In addition, certain areas of LNG carriers are fitted with dry chemical powder-type extinguishing systems and carbon dioxide smothering systems for fighting fires. Fire protection must include the following systems:

- a water spray (deluge) system that covers the accommodation house control room and all main cargo valves;
- a traditional firewater system that provides water to fire monitors on deck and to fire stations found throughout the vessel;
- a dry chemical fire extinguishing system for hydrocarbon fires; and
- a carbon dioxide system for protecting machinery including the ballast pump room, emergency generators, and compressors.

All LNG vessels entering U.S. waters are required to possess a valid IMO Certificate of Fitness and either a Coast Guard Certificate of Inspection (for U.S. flag vessels) or a Coast Guard Certificate of Compliance (for foreign flag vessels). These documents certify that the vessel is designed and operating in accordance with both international standards and the U.S. regulations for bulk LNG carriers under Title 46, CFR, Part 154. Vessels navigating Canadian waters would have to comply with the requirements set out by the Transport Canada with respect to certification, safety inspections and other regulations (SENES, 2007).

#### 4.12.7.2 Hazards Resulting from Accidents

A review of the history of LNG maritime transportation indicates that there has not been a serious accident at sea or in a port which resulted in a spill due to rupturing of the cargo tanks. However, insurance records, industry sources, and public websites identify a number of incidents involving LNG vessels, including minor collisions with other vessels of all sizes, groundings, minor LNG releases during cargo unloading operations, and mechanical/equipment failures typical of large vessels. Some of the more significant occurrences, representing the range of incidents experienced by the worldwide LNG vessel fleet, are described below:

- **El Paso Paul Kayser** grounded on a rock in June 1979 in the Straits of Gibraltar during a loaded voyage from Algeria to the United States. Extensive bottom damage to the ballast tanks resulted; however, no cargo was released because no damage was done to the cargo tanks. The entire cargo of LNG was subsequently transferred to another LNG vessel and delivered to its U.S. destination.
- **Tellier** was blown by severe winds from its docking berth at Skikda, Algeria in February 1989 causing damage to the loading arms and the vessel and shore piping. The cargo loading had been secured just before the wind struck, but the loading arms had not been drained. Consequently, the LNG remaining in the loading arms spilled onto the deck, causing fracture of some plating.
- **Mostefa Ben Boulaid** had an electrical fire in the engine control room during unloading at Everett, Massachusetts. The ship crew extinguished the fire and the ship completed unloading.
- **Khannur** had a cargo tank overfill into the vessel's vapor handling system on September 10, 2001, during unloading at Everett, Massachusetts. Approximately 100 gallons of LNG were vented and sprayed onto the protective decking over the cargo tank dome, resulting in several cracks. After inspection by the Coast Guard, the Khannur was allowed to discharge its LNG cargo.
- **Mostefa Ben Boulaid** had LNG spill onto its deck during loading operations in Algeria in 2002. The spill, which is believed to have been caused by overflow rather than a mechanical failure, caused significant brittle fracturing of the steelwork. The vessel was required to discharge its cargo, after which it proceeded to dock for repair.
- **Norman Lady** was struck by the USS Oklahoma City nuclear submarine while the submarine was rising to periscope depth near the Strait of Gibraltar in November 2002. The 87,000 cubic meter ($m^3$) LNG vessel, which had just unloaded its cargo at Barcelona, Spain, sustained only minor damage to the outer layer of its double hull but no damage to its cargo tanks.
- **Tenaga Lima** grounded on rocks while proceeding to open sea east of Mopko, South Korea due to strong current in November 2004. The shell plating was torn open and fractured over an approximate area of 20 by 80 feet, and internal breaches allowed water to enter the insulation space between the primary and secondary membranes. The vessel was refloated, repaired, and returned to service.
- **Golar Freeze** moved away from its docking berth during unloading on March 14, 2006, in Savannah, Georgia. The powered emergency release couplings on the unloading arms activated as designed, and transfer operations were shut down.

- **Catalunya Spirit** lost propulsion and became adrift 35 miles east of Chatham, Massachusetts on February 11, 2008. Four tugs towed the vessel to a safe anchorage for repairs. The Catalunya Spirit was repaired and taken to port to discharge its cargo.
- **Al Gharrafa** collided with a container ship, Hanjin Italy, in the Malacca Strait off Singapore on December 19, 2013. The bow of the Al Gharrafa and the middle of the starboard side of the Hanjin were damaged. Both ships were safely anchored after the incident. No loss of LNG, fatalities, or injuries were reported.

Although the history of LNG shipping has been free of major incidents, and no incidents have resulted in significant quantities of cargo being released, the possibility of an LNG spill from a vessel over the duration of the proposed project must be considered. If an LNG spill were to occur, the primary hazard to the public would be from radiant heat from a pool fire. If an LNG release were to occur without ignition, an ignitable gas cloud could form and also present a hazard. Historically, the events most likely to cause a significant release of LNG were a vessel casualty such as:

- a grounding sufficiently severe to puncture an LNG cargo tank;
- a vessel colliding with an LNG vessel in transit;
- an LNG vessel alliding[40] with the terminal or a structure in the waterway; or
- a vessel alliding with an LNG vessel while moored at the terminal.

To result in a spill of LNG, any of the above events would need to occur with sufficient impact to breach an LNG vessel's double hull and cargo tanks. All LNG vessels used to deliver LNG to the proposed project would have double-hull construction, with the inner and outer hulls separated by about 10 feet. Furthermore, the cargo tanks are normally separated from the inner hull by a layer of insulation approximately 1-foot thick.

As a result, many grounding incidents severe enough to cause a cargo spill on a single-bottom oil tanker would be unable to penetrate both inner and outer hulls of an LNG vessel. An earlier Federal Power Commission (predecessor to the FERC) study estimated that the double bottom of an LNG vessel would be sufficient to prevent cargo tank penetration in about 85 percent of the cases that penetrated a single-bottom oil tanker. Previous incidents with LNG vessels have primarily involved grounding, and none of these have resulted in the breach of the double hull and subsequent release of LNG cargo. The likelihood of an LNG vessel sustaining cargo tank damage in a collision would depend on several factors:

- the displacement and construction of both the struck and striking vessels;
- the velocity of the striking vessel and its angle of impact with the struck vessel; and
- the location of the point of impact.

The Federal Power Commission study estimated that the additional protection afforded by the double hull would be effective in low-energy collisions; overall, it would prevent cargo tank penetration in about 25 percent of the cases that penetrated a single-hull oil tanker.

[40] "Allision" is the action of dashing against or striking upon a stationary object (for example, the running of one ship upon another ship that is docked) – distinguished from "collision," which is used to refer to two moving ships striking one another.

In 1995, to assist the Coast Guard in San Juan, Puerto Rico, EcoEléctrica L.P. prepared an analysis of the damage that could result from an oil tanker striking an LNG vessel at berth (FERC, 1996). The analysis assumed a 125,000 $m^3$ LNG vessel and an 82,000-dead-weight-ton tanker carrying number 6 fuel oil without tug assistance. The analysis determined the minimum striking speed to penetrate the cargo tanks of an LNG vessel for a range of potential collision angles. Table 4.12.7.2-1 presents the resulting minimum striking speeds for the two principal cargo systems.

TABLE 4.12.7.2-1

**Minimum Striking Speed to Penetrate LNG Cargo Tanks**

| Angle of Impact | Minimum Striking Speed (knots) | |
|---|---|---|
| | **Spherical Tanks** | **Membrane Tanks** |
| Greater than 60 degrees | 4.5 | 3.0 |
| 45 degrees | 6.3 | 4.0 |
| 30 degrees | 9.0 | 6.0 |
| 15 degrees | 18.0 | 12.0 |

For membrane tanks, the critical beam-on striking speed was 3.0 knots; for spherical tanks, the critical on-beam speed was 4.5 knots. For both containment types, lower angles of impact result in much greater minimum striking speeds to penetrate LNG cargo tanks. In the July/August 2002 issue of *LNG Journal*, the General Manager of the Society of International Gas Tanker and Terminal Operators provided a table that indicated the critical speed necessary for a 20,000-ton vessel to puncture the outer hull of an LNG vessel was 7.3 knots. For a 93,000-ton vessel, the impact speed was 3.2 knots. In neither case does such an impact result in damage to the LNG cargo containment system, nor does it result in a release of LNG.

A more recent significant work in analyzing the potential for an LNG vessel breach was released by the DOE in December 2004. Sandia conducted the research and wrote the report entitled, *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water* (2004 Sandia Report). The 2004 Sandia Report included an LNG cargo tank breach analysis using modern finite element modeling and explosive shock physics modeling to estimate a range of breach sizes for both credible accidental and intentional LNG spill events. Accidental breaching evaluations were based on finite element modeling of collisions of double-hulled oil tankers similar in size and design to LNG ships. The analysis of accidental events found that groundings, collisions with small vessels, and low-speed (less than 7 knots) collisions with large vessels striking at 90 degrees could cause minor vessel damage but would not result in a cargo spill. This is due to the protection provided by the double-hull structure, the insulation layer, and the primary cargo tank of an LNG vessel. High-speed (12 knots) collisions with large vessels striking at 90 degrees were found to potentially cause cargo tank breach areas of from 0.5 to 1.5 meters squared ($m^2$).

The possibility of a LNG release due to an accident, such as a collision or grounding, is considered minimal. In addition, current operational procedures in use by the Coast Guard, such as managing ship traffic, coordinating ship speeds, and active ship control in inner and outer harbors, would also further reduce the potential of LNG spill from accidental causes.

#### 4.12.7.3 Hazards Resulting from Intentional Acts

The 2004 Sandia Report also analyzed credible intentional breaches on LNG carriers up to 145,000 $m^3$ in capacity using modern finite element modeling and explosive shock physics modeling. The events considered for credible intentional acts were based on intelligence and historical data, and ranged from sabotage and hijacking to other types of physical attacks. Physical attacks included those documented to have occurred to several types of international shipping vessels, including attacks with small missiles and rockets, and attacks with bulk explosives.

For intentional scenarios, the size of the cargo tank hole depends on the location of the ship and source of threat. Intentional breach areas were estimated to range from 2 to 12 $m^2$. In most cases, an intentional breaching scenario would not result in a nominal hole area of more than 5 to 7 $m^2$, which is a more appropriate range to use in calculating potential hazards from spills. These hole sizes are equivalent to circular hole diameters of 2.5 and 3 meters.

The 2004 Sandia Report also evaluated cascading damage due to brittle fracture from exposure to cryogenic liquid or fire-induced damage to foam insulation. While possible under certain conditions, the cascading damage was found to not likely involve more than two or three cargo tanks. Cascading events were expected to increase the fire duration but not to significantly increase the overall fire hazard.

The 2004 Sandia Report also included guidance on risk management for intentional spills, based on the findings that the most significant impacts to public safety and property exist within approximately 500 meters (1,640 feet) of a spill due to thermal hazards from a fire, with lower public health and safety impacts beyond 1,600 meters (approximately 1 mile). Large un-ignited LNG vapor releases were found to be unlikely, but could extend from nominally 2,500 meters (8,200 feet) to a conservative maximum distance of 3,500 meters (2.2 miles) for an intentional spill.

In 2008, the DOE released another study prepared by Sandia, entitled *Breach and Safety Analysis of Spills Over Water from Large Liquefied Natural Gas Carriers, May 2008* (2008 Sandia Report). The 2008 Sandia Report assessed the scale of possible hazards for newer LNG vessels with capacities up to 265,000 $m^3$. Using the same methodology as the 2004 Sandia Report, the 2008 Sandia Report concluded thermal hazard distances would be 7 - 8 percent greater than those from vessels carrying 145,000 $m^3$ of LNG, due primarily to the slightly greater height of LNG above the waterline. The 2008 Sandia Report also noted the general design of the larger vessels was similar to the previously analyzed ship designs and, for near-shore facilities, the calculated breach size for intentional scenarios would remain the same. Overall, the 2008 Sandia Report maintained the same impact zones as with the smaller vessels that were analyzed in the 2004 Sandia Report.

In February 2007, the U.S. Government Accountability Office (GAO) published a report assessing several studies, including the 2004 Sandia Report, that had been conducted on the consequences of an LNG spill resulting from a terrorist attack on an LNG vessel (GAO, 2007). The GAO's panel of experts agreed that the most likely public safety impact of an LNG spill would be the radiant heat from a pool fire and suggested that further study was needed to eliminate uncertainties in the assumptions used in modeling large LNG spills on water. After the

GAO report, Congress requested the DOE to further address these research needs. DOE contracted Sandia to conduct a series of large-scale LNG fire and cryogenic damage tests to investigate the larger classes of LNG carriers with capacities up to 260,000 $m^3$, representative of the largest LNG vessels in operation. Sandia conducted the largest LNG pool fire tests done to date and performed advanced computational modeling and ship simulations between 2008 and 2011.

As in the earlier studies, Sandia worked with marine safety, law enforcement, and intelligence agencies to assess threats and credible intentional acts. Scenarios included attacks with shoulder-fired weapons, explosives, and attacks by aircraft and other boats. Sandia identified several ranges of possible hull breaches ranging from 0.005 $m^2$ (Very Small) to 15 $m^2$ (Very Large). Based on the collected pool fire test data and the ship simulations, Sandia concluded that thermal hazard distances to the public from a large LNG pool fire was smaller, by at least 2 to 7 percent, than the results listed in the 2004 and 2008 Sandia Reports.

In order to more robustly analyze the potential for cascading failure of LNG carrier cargo tanks, Sandia use detailed vessel structural and thermal damage models to simulate the effects to a LNG carrier from a spill. For the large breaches considered, Sandia predicts that as much as 40 percent of the LNG released from the cargo tank would remain within the ship's structure. Due to both the cold temperature of the LNG and the heat from a pool fire, the LNG carrier's structural steel would be degraded. The effects could be significant enough to cause the ship to be disabled, severely damaged, and at risk of sinking.

Although LNG ship design and construction practices render simultaneous, multiple tank failures as extremely unlikely, Sandia concluded that sequential multi-tank spills may be possible. If sequential failures were to occur, they would not increase the size of the area impacted by the pool fire but could increase the duration of the fire hazards. Based on this research, Sandia concluded that use of a nominal one-tank spill, with a maximum of a three-tank spill, as was recommended in the 2004 Sandia report, is still appropriate for estimating hazard distances.

#### 4.12.7.4 Regulatory Requirements for LNG Carrier Operations

The Coast Guard exercises regulatory authority over LNG facilities that affect the safety and security of port areas and navigable waterways under Executive Order 10173; the Magnuson Act (50 United States Code [USC] Section 191); the Ports and Waterways Safety Act of 1972, as amended (33 USC Section 1221, et seq.); and the MTSA of 2002 (46 USC Section 701). The Coast Guard is responsible for matters related to navigation safety, carrier engineering and safety standards, and all matters pertaining to the safety of facilities or equipment located in or adjacent to navigable waters up to the last valve immediately before the receiving tanks. The Coast Guard also has authority for LNG facility security plan review, approval, and compliance verification as provided in Title 33, CFR, Part 105.

The Coast Guard regulations in 33 CFR 127 apply to the marine transfer area of waterfront facilities between the LNG vessel and the first manifold or valve located inside the containment. Title 33 CFR 127 regulates the design, construction, equipment, operations, inspections, maintenance, testing, personnel training, firefighting, and security of LNG waterfront facilities. The safety systems, including communications, emergency shutdown, gas detection, and fire protection, must comply with the regulations in 33 CFR 127. Under § 127.019, Downeast would be required to submit two copies of its Operations and Emergency Manuals to the Coast Guard Sector Northern New England at least 30 days prior to the first LNG transfer.

Both the Coast Guard regulations under 33 CFR 127 and FERC regulations under 18 CFR 157.21, require an applicant who intends to build an LNG import facility to submit a Letter of Intent (LOI) to the Coast Guard at the same time the pre-filing process is initiated with the Commission. Consequently, Downeast initially notified the Coast Guard that it proposed to construct an LNG import terminal in Washington County, Maine and submitted an LOI to the Captain of the Port (COTP), Sector Northern New England, on December 20, 2005, with LOI amendments submitted on January 6 and February 8, 2006.[41]

As required by its regulations (33 CFR 127.009), the Coast Guard is responsible for issuing a LOR to the FERC regarding the suitability of the waterway for LNG marine traffic with respect to the following items:

- physical location and description of the facility;
- the LNG vessel's characteristics and the frequency of LNG shipments to or from the facility;
- waterway channels and commercial, industrial, environmentally sensitive, and residential areas in and adjacent to the waterway used by LNG vessels en route to the facility, within 25 kilometers (15.5 miles) of the facility;
- density and character of marine traffic in the waterway;
- locks, bridges, or other manmade obstructions in the waterway;
- depth of water;
- tidal range;
- protection from high seas;
- natural hazards, including reefs, rocks, and sandbars;
- underwater pipes and cables; and
- distance of berthed vessels from the channel and the width of the channel.

In addition to the LOI, 33 CFR 127 and FERC regulations require each LNG project applicant to submit a Waterway Suitability Assessment (WSA) to the cognizant COTP no later than the start of the FERC pre-filing process. Until a facility begins operation, applicants must annually review their WSAs and submit a report to the COTP as to whether changes are required. As indicated in 33 CFR Part 127.007(h), the deadline for these reports should coincide with the LOR anniversary date. Downeast must ensure that all submissions of the annual review coincide with the actual date of the initial LOR, which was issued on January 6, 2009. Therefore, the due date of the next annual review will be January 6, 2015. The WSA must include the following information:

- port characterization;
- risk assessment for maritime safety and security;

[41] FERC regulations requiring the LOI during the pre-filing process were issued in 2005 (70 FR 60440, Oct. 18, 2005) before Downeast initiated the pre-filing process. In 2010, the Coast Guard revised 33 CFR 127 to require submittal of the LOI during the FERC pre-filing period (75 FR 29426, May 26, 2010).

- risk management strategies; and
- resource needs for maritime safety, security, and response.

On June 14, 2005, the Coast Guard published a Navigation and Vessel Inspection Circular – *Guidance on Assessing the Suitability of a Waterway for Liquefied Natural Gas (LNG) Marine Traffic* (NVIC 05-05). The purpose of NVIC 05-05 was to provide the Coast Guard COTPs/Federal Maritime Security Coordinators, members of the LNG industry, and port stakeholders with guidance on assessing the suitability of a waterway for LNG marine traffic. Since 2005, the Coast Guard updated this guidance twice, publishing NVIC 05-08 and NVIC 01-11. The current guidance from the Coast Guard is contained in NVIC 01-11.

As described in 33 CFR 127 and in NVIC 01-11, the applicant develops the WSA in two phases. The first phase is the submittal of the Preliminary WSA, which begins the Coast Guard's review process to determine the suitability of the waterway for LNG marine traffic. The second phase is the submittal of the Follow-On WSA. This document is reviewed and validated by the Coast Guard and forms the basis for the agency's LOR to the FERC.

The Preliminary WSA provides an outline which characterizes the port community and the proposed facility and transit routes. It provides an overview of the expected major impacts LNG operations may have on the port, but does not contain detailed studies or conclusions. This document is used to start the Coast Guard's scoping process for evaluating the suitability of the waterway for LNG marine traffic.

The Follow-On WSA must provide a detailed and accurate characterization of the LNG facility, the LNG tanker route, and the port area. The assessment should identify appropriate risk mitigation measures for credible security threats and safety hazards. The Follow-on WSA provides a complete analysis of the topics outlined in the Preliminary WSA. It should identify credible security threats and navigational safety hazards for the LNG marine traffic, along with appropriate risk management measures and the resources (federal, state, local, and private sector) needed to carry out those measures.

All three NVICs direct the use of the 2004 Sandia Report as the best available information on LNG spills. NVIC 05-08 and NVIC 01-11 also include use of the 2008 Sandia Report. Three concentric Zones of Concern, based on LNG carriers with a cargo carrying capacity up to 265,000 $m^3$, are used to assess the maritime safety and security risks of LNG marine traffic. The Zones of Concern are:

- <u>Zone 1</u> – impacts on structures and organisms are expected to be significant within 500 meters (1,640 feet). The outer perimeter of Zone 1 is approximately the distance to thermal hazards of 37.5 kiloWatts per square meter ($kW/m^2$) (12,000 $Btu/ft^2$-hr) from a pool fire.
- <u>Zone 2</u> – impacts would be significant but reduced, and damage from radiant heat levels are expected to transition from severe to minimal between 500 and 1,600 meters (1,640 and 5,250 feet). The outer perimeter of Zone 2 is approximately the distance to thermal hazards of 5 $kW/m^2$ (1,600 $Btu/ft^2$-hr) from a pool fire.
- <u>Zone 3</u> – impacts on people and property from a pool fire or an un-ignited LNG spill are expected to be minimal between 1,600 meters (5,250 feet) and a conservative maximum

distance of 3,500 meters (11,500 feet, or 2.2 miles). The outer perimeter of Zone 3 should be considered the vapor cloud dispersion distance to the LFL from a worst case un-ignited release. Impacts to people and property could be significant if the vapor cloud reaches an ignition source and burns back to the source.

Once the applicant submits a complete Follow-On WSA, the Coast Guard reviews the document to determine if it presents a realistic and credible analysis of the public safety and security implications from LNG marine traffic in the port. Finally, the Coast Guard issues a LOR. The Coast Guard may also prepare an LOR Analysis (LOR Analysis), which serves as a record of review of the LOR and contains detailed information along with the rationale used in assessing the suitability of the waterway for LNG marine traffic.[42]

#### 4.12.7.5 Downeast's Waterway Suitability Assessment

Downeast submitted a Preliminary WSA for the proposed project to the Coast Guard in December of 2005. In the development of the Follow-On WSA, consultations occurred with the Coast Guard, the Area Maritime Security Committee, and other port stakeholders. As part of its assessment of the safety and security aspects of this project, the COTP Sector Northern New England convened safety and security working groups under the umbrella of the Passamaquoddy Bay/Down East Sub-Committee of the Area Maritime Security Committee (LNG Working Group) and Maine and New Hampshire Port Safety Forum, and participated in ad hoc meetings with the regional U.S. and Canadian response and law enforcement communities. The LNG Working Group, as a whole, convened initially in Ellsworth, Maine, in March of 2006, and subsequent meetings were held in Ellsworth and Eastport, Maine, in April and December 2006, respectively. The consultation process included subsequent collaboration with members throughout the WSA review and validation process.

In addition, a Ports and Waterways Safety Assessment (PAWSA) was conducted in October 2006 to provide a baseline for analyses of navigational safety concerns for the Passamaquoddy Bay port area. The PAWSA is a systematic assessment process designed to identify major waterway safety hazards, estimate risk levels, and evaluate potential measures to reduce risk. Participation in the PAWSA was through invitation and was designed to include a broad cross-section of waterway users, port stakeholders, and maritime professionals. Participants included representatives of the marine industry, pilots, tug operators, passenger/ferry operators, commercial fishing and aquaculture industry, environmental groups, state and local officials, local and regional law enforcement, and federal and provincial governments. Canadian government officials, members of the LNG industry, and concerned citizens' groups were on hand to observe the process.

Downeast submitted the Follow-On WSA to the Coast Guard on December 19, 2006. The Follow-On WSA used three concentric Zones of Concern based on LNG carriers with a cargo

[42] At the time the Coast Guard conducted the waterway review, the guidance in NVIC 05-05 used the term WSR as the title for the LOR Analysis. In order to avoid confusion, the Coast Guard decided to continue referring to its final assessment for the Downeast LNG proposal as the WSR, although the WSR term was eliminated in NVIC 05-08 and NVIC 01-11.

carrying capacity up to 265,000 m³ to assess the maritime safety and security risks of LNG marine traffic in Passamaquoddy Bay.[43]

### Carrier Routes

Imported LNG could be obtained from exporting terminals throughout the world and delivered by LNG vessels to the proposed terminal. There are 19 countries which provide LNG for export: Algeria; Angola; Australia; Brunei; Egypt; Equatorial Guinea; Indonesia; Libya; Malaysia; Nigeria; Norway; Oman; Peru; Qatar; Russia; Trinidad & Tobago; United Arab Emirates, United States, and Yemen with another 5 countries planned or under construction: Canada, Columbia, Iran, Papua New Guinea, and Venezuela. Downeast has not identified specific source(s) for LNG supplies for the proposed project.

An LNG carrier's transit from sea to the Downeast LNG terminal would follow a circuitous route through Canadian waters.[44] This is virtually the same route as currently used by all deep-draft vessels servicing the Passamaquoddy Bay port area. Deep-draft vessels bound for the ports of Bayside, New Brunswick, or Eastport, Maine, either enter the area via the Gulf of Maine and into Grand Manan Channel, or by transiting Grand Manan Basin into the Bay of Fundy. Both routes converge offshore in the general vicinity of the entrance to Head Harbour Passage, north of Campobello Island.

The LNG carrier would continue on its northeasterly course into Canadian waters, roughly paralleling the east and northeast coasts of Campobello Island, New Brunswick, to the entrance of Head Harbour Passage. At this point, the LNG carrier would enter Head Harbour Passage. Here it would pass Campobello Island along the island's north shore, then Friar Roads south of Indian Island and Cherry Isle. The carrier would enter U.S. waters as it neared Eastport, Maine. It would pass along Eastport's eastern shore, through Western Passage, pass Quoddy Village in Eastport, Maine, to the west, and pass Deer Island, New Brunswick to the east. The ship's transit would continue north through Western Passage along the international boundary between Canada and the United States, keeping Deer Island to the right and the Maine coast on the left until turning northwesterly back into U.S. waters opposite Lewis Cove to reach the intended project site near the mouth of the St. Croix River. A typical transit, from the time an LNG carrier would enter Head Harbour Passage to the time it reaches the proposed Downeast LNG terminal, would take approximately two and one half to three and one half hours.

All deep-draft vessel traffic entering the Passamaquoddy Bay port area initially navigate Canadian waters, and then straddle the international boundary throughout their respective transits. The existing scheme for ensuring traffic control involves the full cooperation of the United States and Canada. Previously, deep-draft vessel movements were reported to and controlled by "Fundy Traffic," a Canadian marine traffic and communications service center in St. John, New Brunswick. However, Fundy Traffic is no longer in operation and all vessel

[43] Downeast LNG's LOI and WSA were provided to the Coast Guard in 2005 prior to the issuance of the 2008 Sandia Report. The Coast Guard's Waterway Suitability Report states that, "based on the conclusions presented in the Sandia Report of May 2008, the sizes of the hazard zones applied in association with the Downeast LNG site are considered applicable to vessels up to a maximum of 265,000 m³ cargo capacity."

[44] The carrier transit described in this section is from the Coast Guard's January 6, 2009 Waterway Suitability Report for the proposed Downeast LNG facility. The Waterway Suitability Report can be found in Appendix B of the 2009 draft EIS.

movement and communications are controlled remotely. Therefore, the Coast Guard recommends Downeast consult with Transport Canada to determine if this change will compromise the safety of deep draft vessel traffic entering the Passamaquoddy Bay port area and that these results be provided to Coast Guard Sector Northern New Englad for evaluation. The National Vessel Movement Center in the U.S. requires a 96-hour advance notice of arrival for those deep draft vessels calling on U.S. ports.

Both Transport Canada and the U.S. Coast Guard administer Port State Control procedures. If a U.S. Port State Control boarding is required prior to a vessel entering a U.S. port, the boarding would need to take place in U.S. waters, most likely at a point south of West Quoddy Head. Pilotage is compulsory for foreign vessels and U.S. vessels under registry in foreign trade when in U.S. waters. All deep draft ships currently entering the shared waterway via Head Harbour Passage and transiting Maine waters to Eastport must employ a U.S. pilot.

As noted earlier, a typical transit would take approximately two and one half to three and one half hours to traverse the over 16.6 nautical miles from Head Harbour Passage to the proposed terminal. Transit speeds for all LNG marine traffic would be approximately 5 to 10 knots depending on the weather, sea state, and vessel traffic in the area.

LNG carriers leaving the terminal would utilize the same transit routes as described above. A small amount of LNG following cargo unloading at the facility would be retained by the LNG carriers. This volume serves as the "heel" and is the minimum amount of LNG used to insulate the vessel's LNG storage tanks and also serves as fuel for the vessel.

**Hazard Zones Associated with the Proposed Route**

As discussed in section 4.12.7.2 and 4.12.7.3, Sandia National Labs identified three different hazard zones based on accidental and intentional events. The Coast Guard NVIC 01-11 references the three larger intentional "Zones of Concern" for assisting in a risk assessment of the waterway. As LNG carriers proceed along the intended track line, Zone 1, the potential area with the most severe impact, would not affect any high population area or public or government centers such as schools, hospitals or transportation infrastructure.[45] However, Zone 1 may overlap any commercial vessel intended for the Port of Bayside as the vessel passes the berthed LNG carriers. Similarly, recreational and fishing vessels may fall within Zone 1, depending on their course. The seasonal ferry crossings connecting Deer Island, New Brunswick and Eastport, Maine and Campobello Island, New Brunswick could fall within Zone 1 as an LNG carrier passes these ferry crossings. Transit of such vessels through a Zone 1 area of concern can be avoided by timing and course changes, if conditions permit.

During the LNG carrier's transit, Zone 1 would encompass portions of Moose Island on the Maine side and Deer Island on the New Brunswick side. This area presents the narrowest point in the entire transit route and the pilots tend to hug the U.S. side of the dogleg, rather than stay in the middle of the channel, in order to avoid the divergent currents common to this portion of the waterway. Although no major military post or camp is situated along the waterway, Coast Guard

[45] As discussed in section 4.12.7.2, the Coast Guard used criteria developed by Sandia to define the outer limits of the hazard zones for assessing potential risks associated with the proposal. The Coast Guard's January 6, 2009 Waterway Suitability Report (WSR) defines the areas along the transit route that fall within each zone.

Station Eastport, a Search and Rescue and Law Enforcement installation, is located on the shore of Eastport and would fall within Zone 1 and/or 2, depending on the actual course taken by the pilots when navigating the bend off Dog Island. When the carriers transit Head Harbour Passage, the northern most edge of Head Harbour and shore side neighboring areas on Campobello Island would fall within Zone 1, including portions of Wilson's Beach. When the carriers transit Friar Roads and Western Passage, the western edge of Deer Island Point, New Brunswick, including Deer Island Campgrounds, would also fall into this zone.

Zone 2 areas, defined as those where the impact is significant but reduced, include most of Eastport, Kendall Head, and Pleasant Point, Maine, including residential, commercial (e.g. East Coast Ferries, Quoddy Tides Newspaper, restaurants, etc.), and institutional (e.g., Eastport Elementary School, Shead High School, Beatrice Rafferty School, Eastport Police Department, Peavey Memorial Library, U.S. Post Office) land uses. A portion of Route 190, the only vehicle access to and from the City of Eastport, is within Zone 2.

During LNG vessel transits of Head Harbour Passage, all Canadian areas and communities along the northern and westerly edges of Campobello Island such as Brown Head, Wilson's Beach, Windmill Point, and Bald Head would fall within Zone 2. Also within this zone would be the islands off the coast of New Brunswick to include Spruce Island, Sandy Island, Casco Bay Island, Green Island, Pope Island and Indian Island. Zone 2 would also impact land masses along Friar Roads and Western Passage such as West Deer Island, New Brunswick communities west of Highway 772, Doctors Cove, Cummings Cove, and Mink Point.

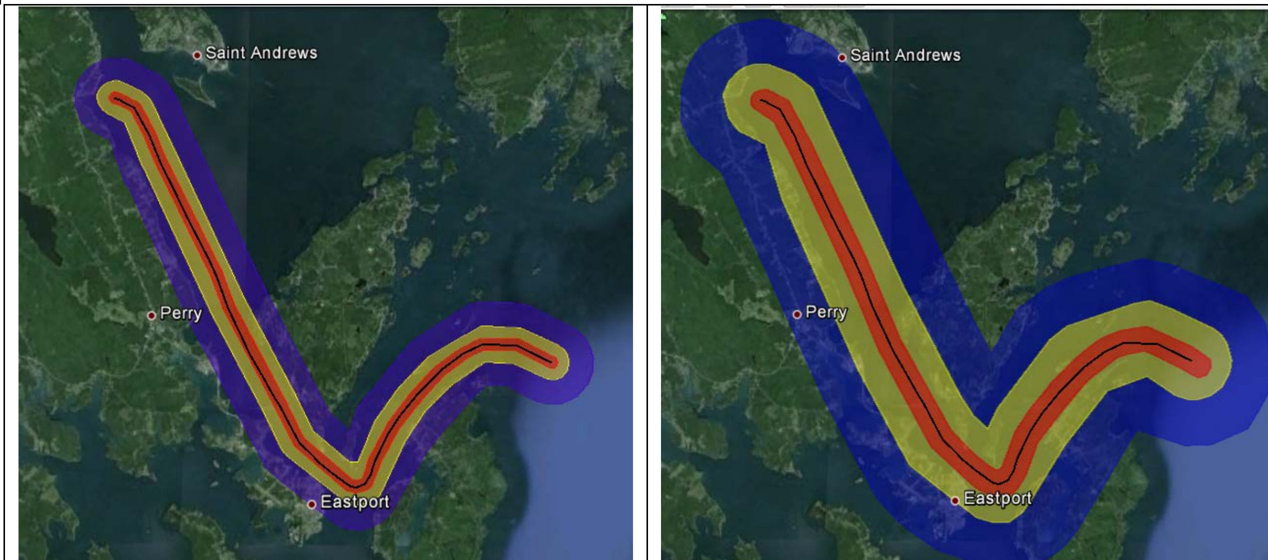
Zone 3 would include areas such as Leonardville, Bar Island, and a portion of Southern Deer Island. Welshpool and all of Northern Campobello Island would fall into Zone 3, as would the communities on the alternate side of Head Harbour Passage. When LNG vessels navigate Friar Roads and Western Passage, a major portion of western Deer Island would fall within this zone as well. Zone 3 would also include Eastport and Moose Island, Pleasant Point, Perry, Robbinston, and Saint Andrews, including residential (e.g., Passamaquoddy Pleasant Point Reservation), commercial (e.g., Eastport Municipal Airport, Federal Marine Terminals), institutional (e.g., Passamaquoddy Tribal Government, Eastport Chamber of Commerce, Robbinston Volunteer Fire Department, Border Historical Museum, Campobello Island Consolidated School, Christ Episcopal Church), and recreational (e.g., Shackford Head State Park, Clark Gregory Nature Preserve, Monument Square, Centennial Park, Algonquinn Golf Course, Saint Andrew's Blockhouse) land uses.

The areas impacted by the three different hazard zones are illustrated for both accidental and intentional events in figure 4.12.7-1. More detailed figures may be found in Appendix F.

#### 4.12.7.6 Coast Guard Waterway Suitability Report

On January 6, 2009, the COTP, Sector Northern New England, issued an LOR and a Waterway Suitability Report (WSR) that summarized the Coast Guard's recommended risk mitigation measures, as well as the port community's capabilities.[46]

[46] At the time the Coast Guard conducted the waterway review, the guidance in NVIC 05-05 used the term WSR as the title for the LOR Analysis. In order to avoid confusion, the Coast Guard decided to continue referring to its final




| Accidental | Intentional |
|---|---|

Sandia Hazard Zone 1 (0-500m)
Sandia Hazard Zone 2 (500-1,600m)
Sandia Hazard Zone 3 (1,600-3,500m)

**Figure 4.12.7-1 Hazard Zones Along LNG Carrier Route**

Based on the results of the assessment of potential risks to navigation safety and maritime security associated with the Downeast proposal[47], the Coast Guard determined the waterway along the proposed carrier transit route would be suitable for the type and frequency of LNG marine traffic associated with this proposed project, provided that the risk mitigation measures defined in the WSR are implemented. The hydrographic characteristics of the waterway are suitable to sustain deep draft vessel movement and the simulation tests and traffic studies confirm the transit and maneuvers are feasible for the design range of LNG carriers anticipated. These measures are further detailed in the WSR and include, among others, the following requirements:

- The development, by Downeast, of standard operating parameters approved by the Coast Guard and coordinated with the Government of Canada to enable the safe and secure movement of LNG tankers through Canadian and U.S. waters, taking into account the need for:
    1) Number and performance capabilities of assist tugs and escort vessels as well as determining appropriate staging areas. The minimum specified number of escort/assist tugs must be employed at all times to escort LNG carriers throughout their transit and during berthing and unberthing. It should be noted that additional

assessment for the Downeast LNG proposal as the WSR, although the WSR term was eliminated in NVIC 05-08 and NVIC 01-11.

[47] We received comments from the House of Commons and Embassy of Canada opposed to the passage of LNG tankers through Head Harbour Passage, which is located within Canadian internal waters.

requirements for escort tugs may be identified during the emergency response planning process.

2) Identification and implementation of navigation safety upgrades and enhancements, as identified in Downeast's WSA, to include but not limited to: radar, communications interoperability, data buoys, and critical Aids to Navigation.

3) Safe operating parameters and environmental constraints, to include but not limited to: visibility, wind, sea state, currents, and tides.

4) These parameters must include the following:

   - Daylight Transits – Loaded or partially loaded LNG carriers may only transit the waterway during daylight hours. "Daylight" is interpreted as "civil twilight" in which the sun may be below the horizon, but the "horizon is clear and larger stars visible (Dutton's Navigation and Plotting). In practical terms, the horizon, shoreline and receiving berths must be clearly seen under conditions of natural light;

   - Visibility – A minimum of two miles of visibility is required for the movement of LNG vessels in U.S. waters. Since in marginal weather conditions visibility can vary significantly along the route, the decision as to whether sufficient visibility exists, and is likely to continue to exist for the transit, is a judgment call that will be made jointly between the attending pilot(s) and Transport Canada, in consultation with and the concurrence of the COTP. The minimum visibility limits must be commensurate with the combined safety and security parameters;

   - Wind – 25 knots is the maximum sustained wind speed (determined during simulation tests), as measured on the vessel, in which an inbound or outbound transit will be allowed to commence. As with visibility, significant variation in wind conditions can exist along the route, and the decision as to whether wind conditions permit a safe transit will be made by the attending pilot(s) in consultation with, and concurrence by, the COTP;

   - Traffic Control – One-way traffic patterns for deep-draft transits will be required and strictly enforced whenever LNG carriers are moving to avoid meeting or passing situations. At the discretion of the attending pilots and in consultation with vessel masters and Transport Canada, all vessel transits will be on a first-come, first-served basis, with inbound vessels having priority over outbound;

   - Anchoring – There are presently no designated (i.e., anchorages specified in regulation) for the area. However, three locations are routinely used: one located in the Bay of Fundy just outside of the transit corridor and to the north of Head Harbour Passage; one in the vicinity of Friars Roads southeast of Eastport; and one inside of Passamaquoddy Bay. LNG vessels will not be allowed to anchor, or hold, in Friar Roads while waiting for a berth – anchoring or holding under this circumstance must occur offshore;

   - Loaded, inbound LNG carriers transiting Head Harbour Passage and Western Passage must maintain ample separation distance and uphold, at a minimum, the safety and security zone parameters. The intent of this limitation is to preclude the possibility of incurring overtaking situations and/or the need for holding at, or anchoring in Friar Roads. Non-LNG vessels may anchor in, or hold at Friar Roads while waiting for a vessel proceeding in the opposite direction to transit Head Harbour Passage or Western Passage; and

  - With the exception of temporary boarding areas established by and for Coast Guard authorized assets, the anchoring or holding of LNG vessels within Friar Roads is limited to confirmed emergency situations only, such as major mechanical malfunctions and reduced visibility situations following non-forecasted, abrupt weather changes (fog, squalls, etc.) and/or as directed by, and in consultation with, the COTP.

- The development by Downeast, of an ERP required by Section 311 of EPAct 2005, 15 U.S.C § 717b-1(e), approved by the FERC and accepted by the Coast Guard to enable a comprehensive and coordinated response to an LNG emergency, taking into account the need for:

  1) In-transit and dockside emergency procedures in the event of fire, mechanical malfunction, allision, grounding, and/or need of safe anchorage or refuge;
  2) The potential environmental impact of an LNG release and the identification and acquisition of joint resource needs to respond to the potential release;
  3) A contingency response plan specific to LNG and focusing on a layered response approach;
  4) Coordinated marine firefighting training and emergency response, with an emphasis on containing and extinguishing LNG fires; and
  5) An incident management training and collaborative exercise program.

- Collaboration with all appropriate jurisdictions on a joint, complementary rulemaking to formalize vessel traffic management practices and the establishment and enforcement of comprehensive safety and security zones for the protection of the LNG carrier, alternate waterway users, and area residents, taking into account the need for:

  1) A one-way vessel traffic scheme during transit operations;
  2) Deep-draft vessel tug escorts and assistance services;
  3) Mandatory pilotage throughout the transit route and during docking and undocking evolutions at all ports along the waterway;
  4) Implementation of an Automatic Identification System for all vessels involved in the transport of LNG on this waterway;
  5) Implementation of appropriate vessel speed restrictions; and
  6) Implementation of appropriate environmental operating parameters (e.g. currents, tides, visibility, wind velocity, etc.).

All the safety and security zones associated with the transiting LNG marine traffic would move with the LNG vessel. As stated in the WSR, the average time for the zone to pass any given point would be approximately 18 minutes. Proper voyage planning and paying attention to advanced Broadcasts to Mariners should be used to alleviate potential conflicts with the moving safety and security zones associated with LNG marine traffic.

- Downeast must develop and successfully conduct full mission bridge simulator training for all pilots providing services to LNG carriers. The training must take into account the full spectrum of vessel design and length, cargo carrying capacity, method of propulsion, steering and rudder configuration, thruster arrangements, and maneuvering characteristics for those carriers being considered for charter. In addition, expanded simulator training incorporating the number and design of tug boats having the minimum performance and operating criteria previously outlined, would be required.
- Downeast must develop a Transit Management Plan (TMP) or other document, in consultation with the Coast Guard and other cognizant agencies, that clearly outlines the roles, responsibilities, and specific procedures for the LNG carrier, the LNG terminal, and all federal, state/provincial, and local stakeholders with responsibilities related to the proposed project and/or whose jurisdiction may reasonably be expected to be impacted by a potential navigation safety accident or terrorist attack.
- The applicant must prepare and submit an Operations Manual, as required by 33 C.F.R. § 127.305, an Emergency Manual, as required by 33 C.F.R. § 127.307, and a Facility Security Plan as required by 33 C.F.R. § 105.120 to the COTP Sector Northern New England for review and approval at least 6 months but no more than 12 months before the facility would begin operations. In its comments as a coopering agency, the Coast Guard Sector Northern New England revised this timeline and stated that under 33 CFR Part 127.019, Downeast would be required to submit two copies of its Operations and Emergency manual to Coast Guard Sector Northern New Englad at least 30 days prior to its first transfer of LNG. Additionally, at least 60 days prior to commencing operations, Downeast would need to submit a Facility Security Plan in accordance with 33 CFR Part 105.410 to the Coast Guard Sector Northern New England.
- The applicant must provide written verification to the Coast Guard of collaboration with and acceptance from the Passamaquoddy Nation, ensuring its jurisdictional interests and public safety and security needs associated with this project are adequately met.

The risk mitigation measures in the WSR also provide that Downeast must determine and comply with all Canadian laws and regulations applicable to safe and secure navigation and the regulation of maritime traffic that comply with customary international law. The Coast Guard indicated that such laws and regulations should not discriminate among foreign ships or in their application have the practical effect of denying, hampering, or impairing the right of non-suspendable innocent passage through an international strait. Moreover, consistent with international law, the Coast Guard will not require compliance with such laws and regulations that apply to the design, construction, manning, or equipment of foreign ships unless they are giving effect to generally accepted international rules or standards.

Based on its review of the WSA, the Coast Guard determined that the Passamaquoddy Bay navigation channel would be suitable for the type and frequency of LNG marine traffic associated with the proposed project. This determination is contingent upon implementation of the recommended measures outlined in the WSR to responsibly manage the maritime safety and security risks. These safety and security measures would be incorporated into a TMP, developed in consultation with the Coast Guard, area stakeholders, and other cognizant agencies. This plan would clearly spell out roles, responsibilities, and specific procedures for LNG marine traffic transiting Passamaquoddy Bay up to the terminal, as well as for all agencies involved in implementing security and safety during the operation.

The Coast Guard's LOR is a recommendation on the current status of the waterway to the FERC, the lead agency responsible for siting the on-shore LNG facility. Neither the Coast Guard nor the FERC has authority to require waterway resources of anyone other than the applicant under any statutory authority or under the ERP or the Cost Sharing Plan (see section 4.12.8). However, as a general proposition, the Coast Guard in its WSR directed Downeast to "adequately demonstrate that an effective security regime has been established during the Canadian portion of the vessels' planned route prior to a loaded LNG vessel being allowed to transit to the facility." For Downeast to "adequately demonstrate" that an effective security regime has been established, it must show that the vessel is being provided with, and has the ability to implement, security measures that are at least equivalent to the level of security required for vessels transiting waters of the United States with similar characteristics (e.g., population densities, key port areas, critical infrastructure, etc.).

Although the LOR and WSR each provide a list of suggested mitigation measures for responsibly managing the maritime safety and security risks associated with LNG marine traffic, the necessary vessel traffic and/or facility control measures may change depending on changes in conditions along the waterway. The Coast Guard regulations in 33 CFR 127 require that applicants annually review WSAs until a facility begins operation. Accordingly, Downeast is required to submit a report to the Coast Guard identifying any changes in conditions, such as changes to the port environment, the LNG facility, or the tanker route, that would affect the suitability of the waterway. Downeast's provided substantiation of its internal review to the Coast Guard on September 13, 2011. In a letter dated November 10, 2011, the Coast Guard responded that the updates did not change the overall port environment, nor did they affect the suitability of the waterway for marine LNG traffic and that the Downeast WSA did not need to be amended at that time.

On March 8, 2013, Downeast submitted the results of their annual review. In its response dated April 3, 2013, the Coast Guard determined that the reported updates in demographics, vessel traffic numbers, and resource capabilities did not substantially change the overall port environment nor affect the suitability of the waterway for marine LNG traffic, and therefore did not constitute a revision of, or amendment to, the WSA at this time. Further, the Coast Guard reminded Downeast that any significant changes to the physical description/layout of the proposed project, modifications to the proposed operation, alterations to the intended transit route, revisions to applied risk management methodologies, and/or changes to identified resource capabilities would need to be provided for Coast Guard review and validation and the WSA updated accordingly. On January 3, 2014, Downeast submitted the results of their latest annual review and on February 24, 2014, the Coast Guard determined that the reported updates to demographics, vessel traffic numbers and resource capabilities were clerical and do not affect the suitability of the waterway for LNG marine traffic.

Under the Ports and Waterways Safety Act, the Magnuson Act, the Maritime Transportation Security Act of 2002, and the Safety and Accountability For Every Port Act, the COTP has the authority to prohibit LNG transfer or LNG vessel movements within his or her area of responsibility if he or she determines that such action is necessary to protect the waterway, port or marine environment. If this project is approved and if appropriate resources are not in place prior to LNG vessel movement along the waterway, then the COTP would consider at that time what, if any, vessel traffic and/or facility control measures would be appropriate to adequately address navigational safety and maritime security considerations. Therefore, **we recommend that:**

- **Downeast should receive written authorization from the Director of OEP <u>before commencement of service</u> at the LNG terminal. Such authorization will only be granted following a determination by the Coast Guard, under its authorities under the Ports and Waterways Safety Act, the Magnuson Act, the Maritime Transportation Security Act of 2002, and the Safety and Accountability For Every Port Act, that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by Downeast or other appropriate parties.**

### 4.12.8 Emergency Response and Evacuation Planning

As required by 49 CFR § 193.2059, Downeast would need to prepare emergency procedures manuals that provide for: a) responding to controllable emergencies and recognizing an uncontrollable emergency; b) taking action to minimize harm to the public including the possible need to evacuate the public; and c) coordination and cooperation with appropriate local officials. Specifically, § 193.2509(b)(3) requires "Coordinating with appropriate local officials in preparation of an emergency evacuation plan…"

Section 3A(e) of the Natural Gas Act, added by Section 311 of EPAct 2005, stipulates that in any order authorizing an LNG terminal, the Commission must require the LNG terminal operator to develop an ERP in consultation with the Coast Guard and state and local agencies. The Coast Guard's WSR also recommends that that the ERP be developed in consultation with the Coast Guard and other cognizant agencies, plus all federal, state/provincial, and local stakeholders with responsibilities related to the proposed project. The WSR states that, "Additionally, bilateral arrangements to ensure appropriate cross-boundary emergency response capabilities under the existing CANUSLANT[48] agreement would be required," but acknowledges that how the ERP development "process applies to Canada and whether Canadian officials will wish to be involved are issues as yet to be determined." The FERC must approve the ERP prior to any final approval to begin construction. Therefore, **we recommend that**:

- **Downeast should develop an ERP (including evacuation) and coordinate procedures with the Coast Guard; state/provincial, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal/tribal agencies. This plan should include at a minimum:**
  - **a. designated contacts with tribal, state and local emergency response agencies;**
  - **b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;**

[48] Acronym for Canada, United States, Atlantic. CANUSLANT refers to the environmental response protocol is in place between the U.S. and Canada for spills of oil and other noxious substances.

c. **procedures for notifying residents and recreational users within areas of potential hazard;**

d. **evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;**

e. **locations of permanent sirens and other warning devices; and**

f. **an "emergency coordinator" on each LNG vessel to activate sirens and other warning devices.**

**The ERP should be filed with the Secretary for review and written approval by the Director of OEP <u>prior to initial site preparation</u>. Downeast should notify the FERC staff of all planning meetings in advance and should report progress on the development of its ERP <u>at 3-month intervals</u>.**

A number of organizations and individuals have expressed concern that the local community would have to bear some of the cost of ensuring the security and emergency management of the LNG facility and the LNG vessels while in transit and unloading at the berth. Section 3A(e) of the Natural Gas Act (as amended by EPAct 2005) specifies that the ERP must include a Cost-Sharing Plan that contains a description of any direct cost reimbursements the applicants agree to provide to any state and local agencies with responsibility for security and safety at the LNG terminal and in proximity to LNG vessels that serve the facility. Therefore, **we recommend that:**

- **The ERP should include a Cost-Sharing Plan identifying the mechanisms for funding all project-specific security/emergency management costs that would be imposed on tribal, state and local agencies. In addition to the funding of direct transit-related security/emergency management costs, this comprehensive plan should include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. The Cost-Sharing Plan should be filed with the Secretary for review and written approval by the Director of OEP <u>prior to initial site preparation</u>.**

The cost-sharing plan must specify what the LNG terminal operator would provide to cover the cost of the tribal, state and local resources required to manage the security of the LNG terminal and LNG vessel, and the state and local resources required for safety and emergency management, including:

- Direct reimbursement for any per-transit security and/or emergency management costs (for example, overtime for police or fire department personnel);
- Capital costs associated with security/emergency management equipment and personnel base (for example, patrol boats, firefighting equipment); and
- Annual costs for providing specialized training for local fire departments, mutual aid departments, and emergency response personnel; and for conducting exercises.

The cost-sharing plan must include the LNG terminal operator's letter of commitment with agency acknowledgement for each state and local agency designated to receive resources.

### 4.12.9 Conclusions on Facility Reliability and Safety

As part of the NEPA review, Commission staff must assess whether the proposed facilities would be able to operate safely and securely to minimize potential public impact. Based on our technical review of the preliminary engineering designs, we conclude that sufficient layers of safeguards would be included in the facility designs to mitigate the potential for an incident that could impact the safety of the off-site public.

DOT reviewed the data and methodology Downeast used to determine the design spills based on the flow from various leakage sources, including piping, containers, and equipment containing hazardous liquids. In a letter to FERC dated January 30, 2014, DOT stated it has no objection to Dowenast's methodology for determining the candidate design spills used to establish the required siting for its proposed LNG import facility. Based on the hazard area calculations performed by Downeast, we conclude that potential hazards from the siting of the facility at this location would not have a significant impact on public safety.

Since 1959, ships have transported LNG without a major release of cargo or a major accident involving an LNG vessel. For the past 40 years, LNG shipping operations have been safely conducted in U.S. ports and waterways. All LNG vessels entering U.S. waters are required to be certified by the Coast Guard as designed and operating in accordance with both international standards and the U.S. regulations for bulk LNG carriers under 46 CFR 154. As a result, the possibility of a LNG release due to an accident, such as a collision or grounding, is considered minimal. In addition, current operational procedures in use by the Coast Guard in U.S. ports, such as managing ship traffic and active ship control in inner and outer harbors, further reduce the potential of LNG spill from accidental causes.

Potential results from intentional acts and threats identified by marine safety, law enforcement, and intelligence agencies must also be considered. Such scenarios, including attacks with shoulder-fired weapons, explosives, and attacks by aircraft and other boats, could result in spills from LNG carriers visiting the proposed project. Security procedures for both the facility and the LNG carriers could be used to reduce the potential of an LNG spill from intentional causes. Both the on-shore facility and the LNG carriers would be subject to stringent requirements for security plan development and approval by the Coast Guard under Title 33, CFR, Parts 104 and 105; the MTSA; the ISPS; and SOLAS.

If an LNG spill were to occur along the waterway, the primary hazard to the public would be from radiant heat from a pool fire. In order to assess the maritime safety and security risks of LNG marine traffic travelling to the proposed facility, hazard distances from both accidental and intentional events were estimated for LNG carriers with cargo capacities up to 265,000 $m^3$. Based on the results of this analysis, the Coast Guard recommended that the waterway along the proposed carrier transit route would be suitable for the type and frequency of LNG marine traffic associated with this proposed project. However, the Coast Guard's recommendation is contingent upon implementation of the recommended measures, outlined in the WSR, to responsibly manage the maritime safety and security risks.

The Coast Guard's WSR, which accompanied the LOR in January 2009, outlined the Coast Guard's validation process and documented those items considered in making the recommendation to the FERC as to the suitability of the waterway for LNG marine traffic.

Although the Coast Guard's WSR was very comprehensive, it was not meant to be all inclusive. Rather, the intent was to provide a summary of the review process that was followed as well as deliver an executive overview of the applicant's WSA - both designed to address potential navigation safety and security risks associated with the proposed transit route.

Additionally, it should be understood that the Coast Guard's LOR is solely a recommendation made to the FERC on whether the COTP considers a particular waterway, in this case the Passamaquoddy Bay and its approaches, suitable for LNG marine traffic from a safety and security perspective. Accordingly, the Coast Guard's LOR should not be perceived as being a form of licensure or federal permitting action, nor does it, within itself, constitute approval or disapproval of any given waterway for a specified use. Likewise any/all recommended safeguards and/or risk reduction strategies contained therein, or within the accompanying WSR, should not be perceived as being prescribed conditions by the Coast Guard. However, under the Ports and Waterways Safety Act, the Magnuson Act, the Maritime Transportation Security Act of 2002, and the Safety and Accountability For Every Port Act, the COTP has the authority to prohibit LNG transfer or LNG vessel movements within his or her area of responsibility if he or she determines that such action is necessary to protect the waterway, port or marine environment. If this project is approved and if appropriate resources are not in place prior to LNG vessel movement along the waterway, then the COTP would consider at that time what, if any, vessel traffic and/or facility control measures would be appropriate to adequately address any navigational safety and maritime security considerations.

### 4.12.10 Pipeline Safety Standards

The transportation of natural gas by pipeline involves some incremental risk to the public in the event of an accident and subsequent release of gas. The greatest hazard is a fire or explosion following a major pipeline rupture. Methane, the primary component of natural gas, is colorless, odorless, and tasteless. It is not toxic, but is classified as a simple asphyxiate, possessing a slight inhalation hazard. If breathed in high concentration, oxygen deficiency can result in serious injury or death. Methane has an ignition temperature of 1,000°F and is flammable at concentrations between 5.0 percent and 15.0 percent in air. Unconfined mixtures of methane in air are not explosive. However, a flammable concentration within an enclosed space in the presence of an ignition source can explode. It is buoyant at atmospheric temperatures and disperses rapidly in air.

The DOT is mandated to provide pipeline safety under Title 49, U.S.C. Chapter 601. The Pipeline and Hazardous Materials Safety Administration (PHMSA), OPS, administers the national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. It develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards which set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve safety. PHMSA ensures that people and the environment are protected from the risk of pipeline incidents. This work is shared with state agency partners and others at the federal, state, and local level. Section 5(a) of the Natural Gas Pipeline Safety Act provides for a state agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing the federal standards, while Section 5(b) permits a state agency that does not qualify under Section 5(a) to perform certain inspection and monitoring functions. A state may also act as DOT's agent to inspect interstate facilities within its boundaries; however, the DOT is responsible for enforcement action. The state of Maine is authorized by PHSMA under Section 5(a) to assume all aspects of the safety program for intrastate facilities.

The DOT pipeline standards are published in Parts 190-199 of Title 49 of the CFR. Part 192 of 49 CFR specifically addresses natural gas pipeline safety issues. Under a Memorandum of Understanding on Natural Gas Transportation Facilities (Memorandum) dated January 15, 1993 between the DOT and the FERC, the DOT has the exclusive authority to promulgate federal safety standards used in the transportation of natural gas. Section 157.14(a)(9)(vi) of the FERC's regulations require that an applicant certify that it would design, install, inspect, test, construct, operate, replace, and maintain the facility for which a certificate is requested in accordance with federal safety standards and plans for maintenance and inspection, or shall certify that it has been granted a waiver of the requirements of the safety standards by the DOT in accordance with Section 3(e) of the Natural Gas Pipeline Safety Act.

The FERC accepts this certification and does not impose additional safety standards other than the DOT standards. If the Commission becomes aware of an existing or potential safety problem, there is a provision in the Memorandum to promptly alert DOT. The Memorandum also provides for referring complaints and inquiries made by state and local governments and the general public involving safety matters related to pipeline under the Commission's jurisdiction. The FERC also participates as a member of the DOT's Technical Pipeline Safety Standards Committee which determines if proposed safety regulations are reasonable, feasible, and practicable.

The natural gas pipeline and associated aboveground facilities proposed for the Downeast LNG Project must be designed, constructed, operated, and maintained in accordance with the DOT Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. Part 192 specifies material selection and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion.

Part 192 also defines area classifications, based on population density in the vicinity of the pipeline, and specifies more rigorous safety requirements for populated areas. The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. The four area classifications are defined as follows:

- Class 1 Location with 10 or fewer buildings intended for human occupancy.
- Class 2 Location with more than 10 but less than 46 buildings intended for human occupancy.
- Class 3 Location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of any building, or small well-defined outside area occupied by 20 or more people during normal use.
- Class 4 Location where buildings with four or more stories aboveground are prevalent.

Class locations representing more populated areas require higher safety factors in pipeline design, testing, and operation. Pipelines constructed on land in Class 1 locations must be installed with a minimum depth of cover of 30 inches in normal soil and 18 inches in consolidated rock. Class 2, 3, and 4 locations, as well as drainage ditches of public roads and railroad crossings, require a minimum cover of 36 inches in normal soil and 24 inches in consolidated rock. All pipelines installed in navigable rivers, streams, and harbors must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock.

Class locations also specify the maximum distance to a sectionalizing block valve (10.0 miles in Class 1, 7.5 miles in Class 2, 4.0 miles in Class 3, and 2.5 miles in Class 4). Pipe wall thickness and pipeline design pressures, hydrostatic test pressures, maximum allowable operating pressure, inspection and testing of welds, and frequency of pipeline patrols and leak surveys must also conform to higher standards in more populated areas. The majority of the proposed sendout pipeline route would cross open land that is sparsely populated. About 24 miles of proposed pipeline route would be located in Class 1 areas, and about 4.9 miles would be in a Class 2 area, and 0.9 miles would be located in Class 3 areas. No portion of the sendout pipeline would be in Class 4 areas. In addition, all pipeline interconnects, and pipeline facilities within the fenced enclosures of the meter station, launcher and receiver, and MLVs would be designed and constructed to meet Class 3 requirements.

If a subsequent increase in population density adjacent to the right-of-way indicates a change in class location above existing design for the pipeline, Downeast would reduce the maximum allowable operating pressure or replace the segment with pipe of sufficient grade and wall thickness, if required to comply with the DOT code of regulations for the new class location.

The Pipeline Safety Improvement Act of 2002 required operators to develop and follow a written integrity management program that contained all the elements described in 49 CFR 192.911 and addressed the risks on each transmission pipeline segment. Specifically, the law establishes an integrity management program which applies to all high consequence areas (HCA).

The DOT has published rules that define HCAs where a gas pipeline accident could do considerable harm to people and their property and requires an integrity management program to minimize the potential for an accident. This definition satisfies, in part, the Congressional mandate for DOT to prescribe standards that establish criteria for identifying each gas pipeline facility in a high-density population area.

The HCAs may be defined in one of two ways. In the first method an HCA includes:

- current Class 3 and 4 locations;
- any area in Class 1 or 2 where the potential impact radius[49] is greater than 660 feet and there are 20 or more buildings intended for human occupancy within the potential impact circle;[50] or
- any area in Class 1 or 2 where the potential impact circle includes an identified site.[51]

[49] The potential impact radius is calculated as the product of 0.69 and the square root of the maximum allowable operating pressure of the pipeline in psi multiplied by the pipeline diameter in inches.
[50] The potential impact circle is a circle of radius equal to the potential impact radius.
[51] An identified site is an outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12-month period; a building that is occupied by 20 or more persons on at least five days a week for any 10 weeks in any 12-month period; or a facility that is occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate.

In the second method, an HCA includes any area within a potential impact circle which contains:

- 20 or more buildings intended for human occupancy; or
- an identified site.

Once a pipeline operator has determined the HCAs on its pipeline, it must apply the elements of its integrity management program to those segments of the pipeline within the HCAs. The DOT regulations specify the requirements for the integrity management plan at Section 192.911. The HCAs would be determined based on the relationship of the pipeline centerline to other nearby structures and identified sites. Of the 29.8 miles of the proposed sendout pipeline, Downeast has identified approximately 2.7 miles that would be classified as HCA. The pipeline integrity management rule for HCAs requires inspection of the entire pipeline in HCAs every seven years. Table 4.12.9-1 lists HCA locations by milepost.

TABLE 4.12.9-1

**Locations of High Consequence Areas**

| Beginning Milepost | Ending Milepost | Criteria | Distance To Pipeline | Land Use | Comments |
|---|---|---|---|---|---|
| 15.60 | 16.50 | Class 3 | < 660 feet | Residential - single family | Baring, ME |
| 18.10 | 18.10 | Identified Site | < 660 feet | Truck Stop | Potential for 20+ people |
| 21.40 | 22.40 | Class 2, 20+ houses | 741 ft. PIR | Residential - single family | Woodland, ME. Includes over 20 houses within a 741-ft. radius Potential Impact Radius, plus two identified sites (apartments or churches) near Milepost 22.1 |
| 23.80 | 24.60 | Class 2, 20+ houses | 741 ft. PIR | Residential - single family | Area along U.S. Hwy. 1 with approx. 20 houses inside a 741-ft. radius Potential Impact Radius |

Part 192 prescribes the minimum standards for operating and maintaining pipeline facilities, including the requirement to establish a written plan governing these activities. The sendout pipeline would be continuously monitored from a SCADA system at an operations control center. The control room personnel would be qualified (per Subpart N of 49 CFR Part 192) to identify and respond to abnormal conditions on the pipeline system. Downeast would prepare an Operations and Maintenance Procedures manual for the pipeline system that meets the requirements of 192.605. The pipeline would be patrolled and inspected on the ground on a periodic basis per DOT requirements. The frequency of these inspections would be affected by activity along the pipeline route such as construction or possible encroachment. These inspections would identify conditions indicative of pipeline leaks, evidence of pipeline damage or deterioration, damage to erosion controls, loss of cover, third-party activities or conditions which may presently or in the future affect pipeline integrity, safety, or operation of the pipeline. The pipeline system would participate in the state "One Call" system. The "One Call" system for Maine is the Dig Safe System®, located in Massachusetts, which is enforced by the Maine PUC.

Under Section 192.615, each pipeline operator must also establish an emergency plan that includes procedures to minimize the hazards in a natural gas pipeline emergency. Key elements of the plan include procedures for:

- receiving, identifying, and classifying emergency events, gas leakage, fires, explosions, and natural disasters;
- establishing and maintaining communications with local fire, police, and public officials, and coordinating emergency response;
- emergency shutdown of system and safe restoration of service;
- making personnel, equipment, tools, and materials available at the scene of an emergency; and
- protecting people first and then property, and making them safe from actual or potential hazards.

Part 192 requires that each operator must establish and maintain liaison with appropriate fire, police, and public officials to learn the resources and responsibilities of each organization that may respond to a natural gas pipeline emergency, and to coordinate mutual assistance. The operator must also establish a continuing education program to enable customers, the public, government officials, and those engaged in excavation activities to recognize a gas pipeline emergency and report it to appropriate public officials. The emergency response planning conducted by Downeast would incorporate the requirements of these procedures. Necessary personnel and equipment would be provided by Downeast or by contracting specialized firms.

### 4.12.11 Pipeline Accident Data

The DOT requires all operators of natural gas transmission pipelines to notify the DOT of any significant incident and to submit a report within 20 days. Significant incidents are defined as any leaks that:

- caused a death or personal injury requiring hospitalization; or
- involve property damage of more than $50,000 (1984 dollars[52]).

During the 20 year period from 1994 through 2013, a total of 1,237 significant incidents were reported on the more than 300,000 total miles of natural gas transmission pipelines nationwide.

Additional insight into the nature of service incidents may be found by examining the primary factors that caused the failures. Table 4.12.11-1 provides a distribution of the causal factors as well as the number of each incident by cause.

The dominant causes of pipeline incidents are corrosion and pipeline material, weld or equipment failure constituting 48.2 percent of all significant incidents. The pipelines included in the data set in table 4.12.11-1 vary widely in terms of age, diameter, and level of corrosion control. Each variable influences the incident frequency that may be expected for a specific segment of pipeline.

[52] $50,000 in 1984 dollars is approximately $115,000 as of March 2014 (CPI 2014)

The frequency of significant incidents is strongly dependent on pipeline age. Older pipelines have a higher frequency of corrosion incidents, since corrosion is a time-dependent process. The use of both an external protective coating and a cathodic protection system[53], required on all pipelines installed after July 1971, significantly reduces the corrosion rate compared to unprotected or partially protected pipe.

TABLE 4.12.11-1

**Natural Gas Transmission Pipeline Serious Incidents by Cause (1994-2013) a/**

| Cause | No. of Incidents | Percentage e/ |
|---|---|---|
| Corrosion | 292 | 23.6 |
| Excavation b/ | 211 | 17.0 |
| Pipeline material, weld or equipment failure | 304 | 24.6 |
| Natural force damage | 142 | 11.5 |
| Outside force c/ | 74 | 6.0 |
| Incorrect operation | 33 | 2.7 |
| All other causes d/ | 181 | 14.6 |
| **TOTAL** | 1,237 | - |

a/ All data gathered from PHMSA Significant incident files, March 25, 2014
b/ Includes third party damage
c/ Fire, explosion, vehicle damage, previous damage, intentional damage
d/ Miscellaneous causes or unknown causes
e/ Due to rounding, column does not total 100 percent

Outside force, excavation, and natural forces are the cause in 34.5 percent of significant pipeline incidents. These result from the encroachment of mechanical equipment such as bulldozers and backhoes; earth movements due to soil settlement, washouts, or geologic hazards; weather effects such as winds, storms, and thermal strains; and willful damage.

Older pipelines have a higher frequency of outside forces incidents partly because their location may be less well known and less well marked than newer lines. In addition, the older pipelines contain a disproportionate number of smaller-diameter pipelines which have a greater rate of outside forces incidents because small diameter pipelines are more easily crushed or broken by mechanical equipment or earth movement. Table 4.12.11-2 shows various causes of outside force incidents.

Since 1982, operators have been required to participate in "One Call" public utility programs in populated areas to minimize unauthorized excavation activities in the vicinity of pipelines. The "One Call" program is a service used by public utilities and some private sector companies (e.g., oil pipelines and cable television) to provide preconstruction information to contractors or other maintenance workers on the underground location of pipes, cables, and culverts.

[53] Cathodic protection is a technique to reduce corrosion (rust) of the natural gas pipeline through the use of an induced current or a sacrificial anode (like zinc) that corrodes at faster rate to reduce corrosion.

TABLE 4.12.11-2

**Outside Forces Incidents by Cause (1994-2013) a/**

| Cause | No. of Incidents | Percent of all Incidents b/ |
|---|---|---|
| Third-party excavation damage | 176 | 41.2 |
| Operator excavation damage | 25 | 5.9 |
| Unspecified excavation damage/previous damage | 10 | 2.3 |
| Heavy rain/floods | 72 | 16.9 |
| Earth movement | 35 | 8.2 |
| Lightning/temperature/high winds | 21 | 4.9 |
| Natural force (other) | 14 | 3.3 |
| Vehicle (not engaged with excavation) | 45 | 10.5 |
| Fire/explosion | 8 | 1.9 |
| Previous mechanical damage | 5 | 1.2 |
| Fishing or maritime activity | 7 | 1.6 |
| Intentional damage | 1 | 0.2 |
| Electrical arching from other equipment/facility | 1 | 0.2 |
| Unspecified/other outside force | 7 | 1.6 |
| **TOTAL** | 427 | 99.9 |

a/ Excavation, Outside Force, and Natural Force from table 4.12.11-1.
b/ Due to rounding, column does not total 100 percent.

## 4.12.12 Impact on Public Safety

As stated above, Downeast would comply with the DOT pipeline safety standards as well as regular monitoring and testing of the pipeline. While pipeline failures are rare, the potential for pipeline systems to rupture and the risk to nearby residents is discussed below.

The serious incidents data summarized in table 4.12.12-1 include pipeline failures of all magnitudes with widely varying consequences. Table 4.12.12-1 presents the average annual injuries and fatalities that occurred on natural gas transmission lines in the 5-year period between 2009 and 2013.

TABLE 4.12.12-1

**Injuries and Fatalities - Natural Gas Transmission Pipelines**

| Year | Injuries | Fatalities |
|---|---|---|
| 2009 | 11 | 0 |
| 2010 a/ | 61 | 10 |
| 2011 | 1 | 0 |
| 2012 | 7 | 0 |
| 2013 | 2 | 0 |

a/ All of the public fatalities in 2010 were due to the Pacific Gas and Electric pipeline rupture and fire in San Bruno, California on September 9, 2010.

The majority of fatalities from pipelines are due to local distribution pipelines not regulated by FERC. These are natural gas pipelines that distribute natural gas to homes and businesses after transportation through interstate natural gas transmission pipelines. In general, these distribution lines are smaller diameter pipes and/or plastic pipes which are more susceptible to damage. Local distribution systems do not have large right-of-ways and pipeline markers common to the FERC regulated natural gas transmission pipelines.

The nationwide totals of accidental fatalities from various anthropogenic and natural hazards are listed in table 4.12.12-2 to provide a relative measure of the industry-wide safety of natural gas transmission pipelines. Direct comparisons between accident categories should be made cautiously, however, because individual exposures to hazards are not uniform among all categories. The data nonetheless indicate a low risk of death due to incidents involving natural gas transmission pipelines compared to the other categories. Furthermore, the fatality rate is much lower than the fatalities from natural hazards such as lightning, tornados, or floods.

TABLE 4.12.12-2

**Nationwide Accidental Deaths a/**

| Type of Accident | Annual Number of Deaths |
|---|---|
| All accidents | 117,809 |
| Motor vehicle | 45,343 |
| Poisoning | 23,618 |
| Falls | 19,656 |
| Injury at work | 5,113 |
| Drowning | 3,582 |
| Fire, smoke inhalation, burns | 3,197 |
| Floods b/ | 89 |
| Lightning b/ | 52 |
| Tornado b/ | 74 |
| Natural gas distribution lines c/ | 14 |
| Natural gas transmission pipelines c/ | 2 |

a/ All data, unless otherwise noted, reflects 2005 statistics from U.S. Census Bureau, Statistical Abstract of the United States: 2010 (129th Edition) Washington, DC, 2009; http://www.census.gov/statab.

b/ NOAA National Weather Service, Office of Climate, Water and Weather Services, 30 year average (1983-2012) http://www.weather.gov/om/hazstats.shtml.

c/ PHMSA significant incident files, March 25, 2014. http://primis.phmsa.dot.gov/comm/reports/safety/, 20 year average.

The available data show that natural gas transmission pipelines continue to be a safe, reliable means of energy transportation. From 1994 to 2013, there were an average of 62 significant incidents, 10 injuries and 2 fatalities per year. The number of significant incidents over the more than 300,000 miles of natural gas transmission lines indicates that the risk is low for an incident at any given location. The operation of the sendout pipeline would represent a slight increase in risk to the nearby public.

## 4.13 CUMULATIVE IMPACTS

In 40 CFR 1508.7, the President's CEQ defines cumulative impacts as the "impacts on the environment that result from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (federal or non-federal) or person undertakes such other actions." Although the individual impact of each individual project may be minor, the additive or synergistic impacts from multiple projects could be significant. Impacts subject to cumulative effects analysis for the Downeast LNG Project were identified by determining the environmental impact issues associated with the proposed action; establishing the geographic scope of the study area; establishing the time frame of the analysis; and identifying other past, present, and/or reasonably foreseeable future actions that have affected, or could affect, the resources of concern.

For this analysis, we looked at potential impacts from known projects existing or proposed along Passamaquoddy Bay and/or near the proposed LNG terminal, LNG projects that would use the M&NE system, and other relevant projects in Washington County. More geographically distant projects (e.g., Northeast Gateway LNG, Neptune LNG, Cacouna Energy LNG, Rabaska LNG) are not assessed because their impact would generally be localized and, therefore, would not contribute significantly to cumulative impacts in the proposed project area.

Construction of the Downeast LNG Project would result in both short- and long-term, minor to moderate environmental impacts. Impacts associated with construction and operation of the LNG terminal would be permanent (e.g., land use change) and temporary (e.g., construction-related noise). Impacts associated with construction and operation of the pipeline generally would be short-term and minor because resources within the area affected by construction would be restored or allowed to revegetate following pipeline installation. Some long-term impacts could occur, however, if resources cannot be restored to original conditions (e.g., cleared forest lands), or when resources are permanently affected due to operational and maintenance requirements (e.g., vegetation maintenance within the operational pipeline rights-of-way).

The environmental impact analysis contained in this EIS indicates that pipeline construction and operation activities for the Downeast LNG Project would result in short-term and minor impacts associated primarily with construction across waterbodies and wetlands, fish and other wildlife habitats, recreation, socioeconomics, transportation, and noise. Long-term impacts associated with construction of the LNG terminal and pipeline-related, aboveground facilities are somewhat greater, and would include the permanent clearing of timber at the terminal and along the permanent pipeline right-of-way, and the prohibition of construction or excavation above the subsurface pipeline. Although these types of impacts were not considered significant for the Downeast LNG Project, they were considered on a cumulative impact basis in association with the review of other identified projects in the area.

The cumulative impact analysis in the draft EIS considered other approved, constructed, proposed, or announced LNG facilities in Maine and Maritimes Canada. However, since publication of the draft EIS, some of these LNG projects (Quoddy Bay, Calais, and Maple) have been put on hold and/or the environmental review process has been terminated. Therefore, these projects are no longer included in our cumulative impacts analysis. In addition, the Pleasant Point/Western Passage Tidal Energy Project has been combined with our analysis of the Tidewalker Tidal Energy Project.

We also contacted officials in eastern Washington County, Maine, to identify other projects that should be addressed in this cumulative impacts analysis. Responses were received from officials in Calais and Eastport, Maine. The COE has recorded more than two hundred permit actions in the area since 1988; most had limited impacts on aquatic resources and qualified for general permits. The exceptions are the two completed M&NE Pipeline projects listed below. The projects included in our cumulative impacts analysis consist of the following:

- Downeast LNG Project – Robbinston, Maine. Described in section 2.0 of this EIS.
- EMEC electric transmission line – Robbinston, Maine. This is a nonjurisdictional facility associated with the Downeast LNG Project. The facility and potential environmental impacts are described in section 2.9 of this EIS.
- Canaport LNG Project – St. John, New Brunswick, Canada. Canaport LNG Project is an LNG receiving, storage, and regasification terminal in St. John, New Brunswick that started receiving LNG in June 2009. The facility is the first LNG regasification plant in Canada, supplying natural gas to Canadian and American markets. Canaport has two 160,000 $m^3$ storage tanks and potential for addition of a third tank, with a maximum sendout capacity of 1.2 Bcfd. A 90-mile-long pipeline delivers natural gas from the Canaport LNG site to an interconnection with the M&NE pipeline near the U.S. border.
- Deep Panuke Offshore Gas Development Project – Southeast of Halifax, Nova Scotia, Canada. Installation of a jack-up mobile offshore production unit (MOPU), a maximum of nine subsea wells (five production, one injection, and three future production wells), up to nine 10-inch-diameter subsea production flowlines tied to the MOPU, and a 22-inch-diameter subsea pipeline connecting to M&NE's facilities in Goldboro, Nova Scotia. Onshore components will consist of monitoring, pressure-control, and pig launching and receiving facilities, in addition to a small building housing SCADA equipment. Gas production began in mid-2013.
- M&NE Pipeline Project, Baileyville to Westbrook, ME – Approximately 347 miles of gas pipeline, consisting of 200 miles of mainline between Westbrook (York County) and Baileyville (Washington County) and 147 miles of lateral pipeline; two new compressor stations; twelve new meter stations; and associated aboveground facilities. The Commission authorized the project in July 1998 and it was placed into service in December 1999.
- M&NE Phase IV Project – various counties in Maine and Massachusetts. Expansion of M&NE's existing system consisting of 1.7 miles of new 30-inch-diameter pipeline in Washington County, Maine; two new aboveground meter stations (Washington and Cumberland Counties, Maine); five new compressor stations (Hancock, Penobscot, Waldo, Cumberland, and York Counties, Maine); and minor modifications to existing compressor and meter stations (Washington and Sagadahoc Counties, Maine and Essex County, Massachusetts). The Commission authorized the Phase IV Expansion Project on February 15, 2007. Construction was completed and the facilities placed into service in January 2009.
- Tidewalker Tidal Energy Project – Half Moon Cove, Cobscook, Maine. Tidewalker Tidal Energy Project (Tidewalker) would involve construction of a dam at the location of

a former toll bridge connecting Moose Island (Eastport, Maine) to the mainland at Perry, Maine. The proposed dam would be approximately 1,210 feet long with a maximum depth of 40 feet below MSL and a maximum elevation of 27 feet above MSL. Two small dams existing along the easterly perimeter of Half Moon Cove were constructed in the 1930s to isolate the tidal basin from Passamaquoddy Bay. Half Moon Cove discharges into Cobscook Bay at the site of the proposed rockfill dam/powerhouse. Tidewalker received a preliminary permit from FERC in April 2007 to develop a full permit and license application for this location (P-12704). The integrated licensing process was terminated by FERC in November 2009, and an application for a successive preliminary permit was filed in March 2010 with the Maine DEP (Maine DEP 2010). A final application to FERC is anticipated in 2014.

- Halcyon Pennamaquan Tidal Energy Project - Pennamaquan Estuary, Town of Pembroke, Maine. A 1,500-foot-long Halcyon Enclosure will consist of up to 17 Alstom Power bulb turbine gensets placed horizontally within the powerhouse caissons at the center, a boat lock and concrete minicaissons reaching to each shoreline. Power output is expected to be at least 25.6 MW. The facility will interconnect with an upgraded transmission line on Hershey Neck Road which terminates at the Bangor Hydro Electric Company substation in Pembroke. Completion is expected in 2017.
- Ocean Renewable Power Company (ORPC) Western Passage Tidal Energy Project – (Eastport tidal sites at Western Passage of Passamaquoddy Bay and at Cobscook Bay). The project consists of a tidal (or ocean) current electric power generation facility that would utilize a series of underwater ocean current generation modules. No dams, spillways, penstocks, powerhouses, tailraces, or other structures within or near the proposed tidal energy project area would be constructed as part of this proposed project. ORPC received preliminary permits from FERC in July 2007 (P-12711 for Cobscook Bay and P-12680 for Western Passage). The notice of intent to file a license application and draft application for a pilot project license was filed in July 2009. ORPC placed its first prototype turbine generator unit online at the Cobscook Bay site in September 2012, and will evaluate production for about three years to determine the potential for large scale power production.
- U.S. Route 1 Reconstruction – Eastport to Calais, Maine. Reconstruction of U.S. Route 1 along the 12 miles between Eastport and Calais was completed in summer 2008 (Maine DOT 2007).
- Border Crossing – Calais, Maine. Construction of a new border crossing facility between the United States and Canada completed in November 2009.
- Atlantic Salmon Aquaculture Facilities – Eastport, Maine. Cooke Aquaculture Inc. conducted a rehabilitation of aquaculture facilities on the coast. The facilities are currently in operation.
- Port of Eastport Gateway Project – Eastport, Maine. The port is in the planning phase of this project that would be designed to restore rail freight service to the port of Eastport. The port is also developing a proposal to replace the existing breakwater pier with a new municipal pier. Existing facilities at the port include the Estes Head Cargo Terminal, which can accommodate a ship of 900 feet in Berth A and one up to 550 feet in Berth B.

Berth B also accommodates barges. There are several open storage areas and warehouses on the site. The operations are supervised from the Federal Marine Terminal offices located above the Estes Head pier. Approach depths to the Estes Head pier are in excess of 100 feet, and the mean low water depth is 64 feet.

- Stetson Mountain Wind Power Project –Washington County, Maine. Proposed by First Wind, to include 38 wind energy turbines (57 megawatts) on a ridgeline on Stetson Mountain between the communities of Danforth and Springfield. An application filed with the Maine Land Use Regulation Commission was approved on January 3, 2008. The project officially began generating power on a commercial basis in January 2009. The Stetson Phase II project, which became operational in April 2010, added 17 turbines (25.5 megawatts) on Jimmey and Owl Mountains. First Wind has a 15-year purchase agreement with Harvard University for half of Stetson II's output. The rest is sold to Constellation Energy of Maryland, an energy product and services supplier to wholesale and retail electric customers.

There are several other projects that were announced or proposed in the area, but have been cancelled or the applications withdrawn since issuance of our draft EIS. For this reason, we have not included the following projects in our cumulative impacts analysis.

- Quoddy Bay LNG Project – Pleasant Point, Maine. Quoddy Bay's once proposed LNG terminal site is about 8.0 miles south of Downeast's proposed site. The Quoddy Bay LNG Project would include two LNG ship berths and associated unloading platforms and pipeline, three 160,000 $m^3$ storage tanks, and a 36-mile-long, 36-inch-diameter natural gas sendout pipeline extending from the LNG terminal to the existing M&NE pipeline system at the Baileyville, Maine compressor station. During operation, the Quoddy Bay LNG Project would receive about 60 LNG vessels per year. On October 17, 2008, FERC dismissed Quoddy Bay LNG's application to build and operate an LNG import terminal and associated pipeline.

- Calais LNG Project – Calais, Maine. In December 2009, Calais LNG filed an application with the FERC proposing to construct and operate an LNG import terminal and storage facility in Calais, Maine, about 15 miles north of Downeast's Robbinston, Maine location. The facility would have a nominal sendout capacity of about 1.0 Bcfd and a peak sendout capacity of 1.5 Bcfd. The 330-acre site would include 2,800 feet of shoreline along the St. Croix River and Passamaquoddy Bay. The LNG terminal would be located near Ford Point on the St. Croix River in the City of Calais. The project would also include the installation of a 20-mile-long, 36-inch-diameter sendout pipeline, originating at the LNG terminal and ending at an interconnect with the M&NE pipeline system in Princeton. During operation, the Calais LNG Project would receive about 100 LNG vessels per year. In April 2012, the Commission dismissed Calais LNG's application to build and operate an LNG import terminal and associated pipeline.

- EMEC Transmission Line and Substation to the Calais LNG terminal – If the Calais LNG terminal were constructed, electric power to the terminal would be supplied by EMEC with a direct tie-in to the property site. EMEC would install a new electric transmission line from a proposed switching station located off U.S. Route 9 near King Street in Calais to a new substation that would be located in the LNG terminal property, accessible from

U.S. Route 1. The electric transmission line would be approximately 6.7 miles in length and would consist of a 69-kV line. In its application to the FERC, Calais LNG indicated that more than 95 percent of the new transmission line would be a dual corridor with the Calais LNG sendout pipeline from portions of the route between MP 6.6 to MP 20.7.

- Bear Head LNG Project – Point Tupper, Nova Scotia, Canada. Construction began in 2004, but was placed on hold indefinitely in February 2007 due to lack of long-term LNG supply.
- Maple LNG – Goldboro, Guysborough County, Nova Scotia, Canada. Proposed new LNG import, storage, and regasification facilities with a sendout capacity of 1.0 Bcfd, constructed in association with an adjacent petrochemical complex and an electric co-generation facility. The project received environmental approval by the Nova Scotia Environmental Minister on March 15, 2007 and a construction permit from the Nova Scotia Utility and Review Board in June 2008. However, Maple LNG has since suspended activity on the project and no work is ongoing.
- Commercial Fabrication Facilities – Passamaquoddy Tribal Government, Maine. The project would provide facilities for airplane parts refurbishment and assembly of pre-fabricated homes. The project appears to be on hold.
- M&NE Phase V Project – In April 2008, M&NE entered into the FERC pre-filing process for its planned Phase V Project, which would increase capacity on its system by up to 0.17 Bcfd year-round, plus an additional 0.03 Bcfd capacity during the winter months (FERC Docket Number PF08-17-000). The Phase V Project would provide additional capacity to transport new natural gas supplies from EnCana's Deep Panuke project in Maritimes Canada, and was proposed to be in service in November 2010. However, on March 2, 2009, M&NE notified FERC that it would not proceed with the pre-filing process for the project.
- Pleasant Point/Western Passage Tidal Energy Project – Pleasant Point Passamaquoddy Indian Territory, Western Passage (Kendall Head and First Island). The project proposed by the Passamaquoddy Tribe (contractor, Distributed Generation Systems, Inc., and subcontractor UEK Corporation) would generate less than 5 kW of electric energy, allowing for local distribution to Eastport and Perry, Maine and the Tribe. The Passamaquoddy Tribe received a preliminary permit in November 2007 (P-12710) to test 8-foot underwater turbines at Kendall Head and First Island, which was terminated on May 27, 2010 at the request of the Passamaquoddy Tribe.

Table 4.13-1 presents a summary of the expected cumulative impacts of the Downeast LNG Project and other identified LNG, natural gas pipeline, and industrial/commercial projects identified in the project area. The following is a brief analysis of the cumulative impacts on the resources resulting from the proposed Downeast LNG Project and the other projects listed in table 4.13-1.

TABLE 4.13-1

**Cumulative Impacts of the Downeast LNG Project and Other Projects in the Downeast Project Area**

| Project | Land Disturbance | Marine Disturbance | Marine Transportation | Air Quality | Wetlands | Surface Waterbodies | LNG Safety |
|---|---|---|---|---|---|---|---|
| Downeast LNG | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Canaport LNG | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Deep Panuke Offshore Project | Yes | Yes | Yes | Yes | IU | IU | Yes |
| M&NE Pipeline Baileyville to Westbrook | Yes | No | No | Yes | Yes | Yes | No |
| M&NE Phase IV | Yes | No | No | Yes | Yes | Yes | No |
| Tidewalker Tidal Energy | Yes | Yes | Yes | Yes | No | No | No |
| Halcyon Pennamaquan Tidal Energy | Yes | Yes | No | No | IU | Yes | No |
| Pleasant Point Tidal Energy Project | IU | Yes | Yes | Yes | No | No | No |
| ORPC Western Passage Tidal Energy Project | No | Yes | Yes | Yes | No | No | No |
| ORPC Cobscook Bay Tidal Energy Project | No | Yes | Yes | Yes | No | No | No |
| Atlantic Salmon Aquaculture Facilities | No | Yes | Yes | No | No | No | No |
| U.S. Route 1 Reconstruction | Yes | No | No | Yes | IU | IU | No |
| Calais Border Crossing | Yes | No | No | Yes | Yes | Yes | No |
| Port of Eastport Gateway Project | Yes | No | Yes | Yes | No | No | No |
| Machias Area Airport | Yes | No | No | Yes | Yes | Yes | No |
| Stetson Mountain Wind Project | Yes | No | No | Yes | Yes | Yes | No |

IU = Information unavailable

### 4.13.1 Water Resources

During construction of marine facilities associated with the Downeast LNG terminal, marine surface water quality would be affected primarily from turbidity. However, this impact would be localized and short term, occurring only in the immediate vicinity of the terminal facilities and during construction. Similar surface water impacts would likely occur during construction of the marine components of other projects listed in table 4.13-1. However, because the construction time periods and physical impact areas for these projects would not overlap, cumulative impact on surface water quality from turbidity during construction would be negligible.

During operation, passage of LNG vessels along the 16.6 nautical miles of waterway to the Downeast LNG terminal could potentially affect surface water quality. Based on available information, operation of those projects listed in table 4.13-1 could have cumulative effects to marine water quality as a result of additional marine traffic along the navigation channel, which would involve cooling water withdrawals and discharges, and installation of structures (ocean current generation modules) within the navigation channel. No degradation of water quality is expected during operation of these projects. Water withdrawals and discharges for vessel engine cooling could result in elevated water temperatures and impingement of marine organisms; however, these impacts along the navigation channel would be minor and temporary and would occur over a large area at varying times. In the project area, these impacts would be mitigated by significant tidal fluctuations and high densities of zooplankton and ichthyoplankton, such that the overall impacts on marine organisms in the project area would have an inconsequential effect to overall community populations and associated fish stocks.

The pipeline associated with the proposed Downeast LNG Project would require the crossing of waterbodies. Based on available information, some of the other projects included in table 4.13-1 also involved waterbody crossings by pipelines or roads. However, we do not believe any of the other projects crossed the same waterbodies as the Downeast pipeline; therefore, there would be no cumulative impacts on specific waterbodies.

To minimize impacts on water resources, Downeast has agreed to follow the FERC staff's Wetland and Waterbody Construction and Mitigation Procedures. For the other facilities listed in table 4.13-1 in the United States, each proponent must comply with federal, state, and local permit requirements and crossing methods for each waterbody crossing. For those facilities in Canada, project proponents must follow Canadian regulations and procedures. Generally, impacts from construction of the pipelines and roads across surface waters would be short-term. No long-term or significant cumulative impacts on waterbodies crossed by the projects listed in table 4.13-1 would be expected following restoration.

### 4.13.2 Wetlands

At the proposed location of the Downeast pier, there are approximately 5.91 acres of subtidal wetlands and 0.7 acre of intertidal wetlands. Construction and operation of the marine facilities associated with the Downeast LNG terminal would permanently affect a portion of these tidal wetlands. The acreage of permanent impact on tidal wetlands of other projects included in table 4.13-1 is not known at this time. Downeast has attempted to minimize the area of permanent impact on tidal wetlands through the design and location of the permanent pier. In addition, Downeast would minimize and mitigate for its impacts on wetlands by implementing its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*, as well as providing compensatory mitigation and wetland preservation to satisfy the terms and conditions of its COE Section 404 permit. It is expected that the other projects listed in table 4.13.1 have followed or will follow a similar approach to avoid, minimize, and mitigate for permanent impact on wetlands.

Construction of the pipeline component of the proposed Downeast LNG Project would temporarily affect wetlands. Most of this impact would be short-term, with disturbed areas allowed to revegetate following construction. Impact on forested wetlands within the new operational right-of-way would be long-term, as vegetation maintenance of the pipeline right-of-way would maintain previously forested wetlands in a herbaceous or scrub-shrub cover type. In evaluating alternatives for Downeast's sendout pipeline, we conducted detailed evaluations of route alternatives and route variations. We examined route alternatives that could reduce or avoid impacts on environmentally sensitive resources and route variations that could avoid or reduce construction impacts on specific, localized resources such as particular wetland areas.

Based on available information, the other projects included in table 4.13-1 could also temporarily impact wetlands. In most instances, cumulative effects of the temporary wetland impacts would be minimal because of the limited temporal and spatial overlap between the projects. In addition, each project listed in table 4.13-1 would be required to examine alternatives that avoid or reduce environmental impacts, including impacts to wetlands. For facilities in the United States, each of the project proponents is required to provide compensatory mitigation for unavoidable wetland impacts, as required by the terms and conditions of their respective COE Section 404 permits. For facilities in Canada, project proponents must follow Canadian regulations and procedures. Mitigation measures would be implemented to restore disturbed wetlands in accordance with other federal, state, and local permit requirements.

### 4.13.3 Special Status Species

Consultation with the FWS and NOAA Fisheries identified a number of federal and/or state special status species that may be in the Downeast LNG Project area. The same special status species could occur in the project areas of the other projects listed in table 4.13-1. Lead agencies for federal projects would be required to consult with federal, state and local agencies to determine which species could occur within the project areas in order to evaluate potential impacts on those species and their habitats and to implement measures to avoid, minimize or mitigate the impacts.

The Downeast LNG Project would incrementally add to impacts on ESA-listed whales and other marine mammals protected by the MMPA because of increased vessel traffic along the waterway for LNG marine traffic by as many as 60 vessels per year. The waterway currently sees about 120 vessels per year calling on the ports of Eastport, Maine and Bayside, New Brunswick. The other projects listed in table 4.13-1 may contribute to cumulative impacts on special status species. For example, the Port of Eastport Gateway project on Estes Head could increase traffic by cargo vessels and barges, and the tidal energy projects would add construction and maintenance vessels to the waterway. As a result of these projects, vessel traffic would be expected to increase; however, the potential increase is unknown at this time.

Despite the potential for increased vessel traffic along the waterway, cumulative impacts on protected marine mammals would be mitigated through the vessel strike avoidance plan that each project would be required to implement. Downeast has developed such a plan that would encourage vessels under a charter party agreement to abide by procedures aimed at minimizing and avoiding contact with the whales and incorporate spatial and temporal exclusions pursuant to IMO and NOAA Fisheries guidance and regulations. We believe that with these agreements in effect, adequate mitigation of cumulative impacts on whales would be achieved.

Downeast has identified bald eagle habitat that could be affected by project construction or operation. The bald eagle receives protection under the Bald and Golden Eagle Protection Act, the MBTA, and the Lacey Act. Projects subject to NEPA review would conduct consultation with federal and state agencies to develop and then implement minimization, avoidance and mitigation plans to prevent adverse impacts on the bald eagle. We expect no significant cumulative impacts on this species.

### 4.13.4 Fisheries and Aquatic Resources

During construction of marine facilities associated with the Downeast LNG terminal, marine fisheries and aquatic resources would be affected from disturbance of bottom habitats, increased turbidity, and noise. Resources affected would include designated EFH. These impacts would be localized and short-term, occurring only in the immediate vicinity of the terminal facilities and only during construction. Similar impacts would likely occur during construction of the marine components of other projects listed in table 4.13-1. However, because the construction time periods and physical impact areas for these projects are not expected to overlap, cumulative impacts on marine fisheries and aquatic organisms during construction of the projects would be insignificant.

In addition to the permanent impacts on bottom habitat from the Downeast LNG pier, including possibly on eelgrass from operation of LNG vessels arriving at the pier, based on available information operation of those projects listed in table 4.13-1 also would result in such permanent impacts. There also is a potential impact from the tidal energy projects to affect salmon farming along Western Passage. In addition, operation of the other listed projects with marine facilities potentially would have permanent impacts on marine fisheries and aquatic resources. Downeast has attempted to minimize the area of permanent impact on marine habitat through terminal siting and design. It is expected that the other projects listed in table 4.13-1 have followed a similar approach to avoid, minimize, and mitigate for permanent impact on marine habitats.

During operation, passage of LNG vessels along the 16.6 nautical miles of waterway to the Downeast LNG terminal could potentially affect fisheries and marine mammals, including injury or destruction from vessel strikes, noise harassment, reduced food supply from ichthyoplankton and zooplankton loss and entrainment of juvenile fish resulting from water withdrawals while the vessel is in transit and moored at the LNG terminal. Based on available information, during operation of the marine-related projects listed in table 4.13-1, cumulative effects to marine fisheries and mammals could result from the combination of the additional marine traffic and the construction and maintenance apparatus associated with the tidal energy projects and the ocean current generation modules in or close to the waterway. This would result in an increased potential for vessel strikes with whales or sea turtles. Increasing vessel traffic in the action area also raises concerns about the potential effects of noise pollution on marine mammals and sea turtles, which may result in auditory trauma, temporary or permanent loss of hearing sensitivity, habitat exclusion, habituation, and disruption of other normal behavior patterns such as feeding, migration, and communication. In locations with increased background noise conditions, due to cumulative vessel noise from increased vessel traffic, North Atlantic right whales have been shown to produce vocalizations at a lower rate and at a higher average frequency. Such behavioral changes may be correlated to potential masking effects from increased background noise (Parks et al. 2007). However, further study is needed to determine if such behavioral changes are a direct response to increased noise, and to determine any long-term effects on limiting reproduction and recovery of this species (Parks et al. 2007).

### 4.13.5 Terrestrial Resources

Construction and operation of the proposed Downeast LNG Project would affect terrestrial vegetation and wildlife habitats. Based on available information, construction and operation of the other projects listed in table 4.13-1 would also affect terrestrial vegetation and wildlife habitats. If the projects listed in table 4.13-1 were to be constructed at or near the same time, the combination of construction activities could have a cumulative impact on vegetation and wildlife living in the immediate area. Clearing, grading, and other construction activities associated with the Downeast project, along with other area construction projects, could result in the removal of vegetation, alteration of wildlife habitat, displacement of wildlife, and other secondary effects such as increased population stress, disruption of predator-prey relationships, forest fragmentation, and establishment of invasive plant species. The construction of multiple large industrial projects at or near the same time could result in a significant amount of land clearing activities, with a potential cumulative impact on forest resources in the immediate area of the projects. During construction activities, mobile species would be able to relocate to adjacent habitat and then reoccupy open project lands after those areas were restored. However, for most of the projects listed in table 4.13-1, the construction time periods and physical impact areas are not expected to overlap; therefore, cumulative impacts on terrestrial resources would not be significant.

### 4.13.6 Air Quality and Noise

Construction of the proposed Downeast LNG Project would generate emissions from operation of heavy equipment and worker vehicles, and fugitive dust from ground-disturbing activities. Similar activities during construction of the other projects listed in table 4.13-1 would be expected to generate similar emissions. Cumulative air quality impacts would depend on the timing of construction of each project. However, for most of the projects listed in table 4.13-1, the construction time periods and physical impact areas are not expected to overlap; therefore, cumulative air quality impacts from project construction are not expected to be significant.

During operation, vessel emissions would be generated by the travel of the LNG import vessel, three or four tugs, and an unspecified number of escort vessels within the moving safety/security zone. Emissions in the fixed zone (with vessel moored) would be generated by the LNG import vessel, one standby tug, and one escort vessel. In addition, emissions would be generated from the SCVs, emergency generator, diesel fire pump, seawater fire pump, and emergency venting.

To address the concerns of the public in the region, we requested that Downeast provide a cumulative air quality impact assessment, including existing and proposed emission sources in the region, and including evaluation of impacts on nearby Class I and Class II areas. The impact assessment was consistent with the guidelines published in the Federal Land Managers Air Quality Related Values Workgroup Report. The results are described in section 4.11.1.5. We also evaluated potential cumulative emissions with other emission sources in Washington County. Table 4.13.6-1 compares the criteria pollutant emissions in Washington County with the combined emissions attributable to Downeast operations (stationary and maritime sources). During operation, project emissions of $NO_2$ would represent about 6.3 percent of the county emissions. All other project emissions would represent an even smaller fraction of the Washington County emissions.

Noise produced during construction of the listed projects could create short-term annoyances to nearby residents, and could have short-term impacts on some aquatic species, nesting birds, and other wildlife in the area. Noise impacts during the construction phase would be localized and would attenuate quickly as the distance from the noise source increases. These impacts would be temporary and would only occur during the actual construction activities for the projects. In addition, the projects would be separated by enough distance that noise impacts from construction would not be cumulative.

TABLE 4.13.6-1

**Comparison of Project Emissions with Washington County Emissions** a/

| Pollutant | Terminal Operations (tpy) | Vessel Activities (tpy) | Total (tpy) | Washington County (tpy) | Project Fraction |
|---|---|---|---|---|---|
| Nitrogen Oxides | 70.9 | 46 | 117 | 1,74 | 6.3% |
| Carbon Monoxide | 50.3 | 16.6 | 66.9 | 2,04 | 3.2% |
| $PM_{10}$ | 2.5 | 1.87 | 4.37 | 738 | 0.6% |
| $PM_{2.5}$ | 2.5 | 1.57 | 4.07 | 702 | 0.6% |
| VOCs | 16.7 | 2.14 | 18.8 | 542 | 3.4% |
| Sulfur Dioxide | 1.4 | 5.35 | 6.75 | 588 | 1.1% |

a/ Washington County emissions data from the 2002 dataset: the EPA National Emission Inventory.

During operation, the Downeast LNG terminal would generate noise. Estimated noise levels, and mitigations to ensure that noise levels are below acceptable limits, are described in section 4.11.2.5 of this EIS. As with construction noise, the projects listed in table 4.13-1 would be separated by enough distance that noise impacts during operation would not be expected to be cumulative. In the marine environment, increased vessel traffic from the marine projects listed in table 4.13-1 would result in increased ambient background underwater noise. These cumulative noise levels could cause auditory trauma, temporary or permanent loss of hearing sensitivity, habitat exclusion, habituation, and disruption of other normal behavior patterns, such as feeding, migration, and communication, to marine mammals and sea turtles. However, noise associated with the normal operation of additional vessels along the waterway would likely cause an insignificant incremental increase in noise impacts.

### 4.13.7 Climate Change

Climate change is the modification of climate over time, whether due to natural causes or as a result of human activities. Climate change cannot be represented by single annual events or individual anomalies. For example, a single large flood event or particularly hot summer is not an indication of climate change. However, unusually frequent or severe flooding, or several consecutive years of abnormally hot summers over a large region may be indicative of climate change.

GHG emissions from vessel activity and stationary sources associated with operation of the proposed project are estimated at 208,938 tons $CO_{2e}$.

The Intergovernmental Panel on Climate Change (IPCC) is the leading international, multigovernmental scientific body for the assessment of climate change. The United States is a member of the IPCC and participates in the IPCC working groups. The leading United States scientific body on climate change is the United States Global Change Research Program (USGCRP). Thirteen federal departments and agencies[54] participate in the USGCRP, which began as a presidential initiative in 1989 and was mandated by Congress in the Global Change Research Act of 1990.

The USGCRP have recognized that:

[54] The USEPA, USDOE, Department of Commerce, Department of Defense, Department of Agriculture, Department of the Interior, Department of State, USDOT, Department of Health and Human Services, National Aeronautics and Space Administration, National Science Foundation, Smithsonian Institution, and Agency for International Development.

- Globally, anthropogenic GHGs have been accumulating in the atmosphere since the beginning of the industrial era causing recent global warming;
- Combustion of fossil fuels (coal, petroleum, and natural gas), combined with agriculture and clearing of forests is primarily responsible for the accumulation of GHG;
- The anthropogenic GHG emissions are the primary contributing factor to recent climate change; and
- Impacts extend beyond atmospheric climate change alone, and include changes to water resources, transportation, agriculture, ecosystems, and human health.

The USGCRP issued its Second National Climate Assessment (NCA) titled, Global Climate Change Impacts in the United States, in 2009 summarizing the impacts climate change has already had on the United States and what projected impacts climate change may have in the future. The report includes a breakdown of overall impacts by resource and impacts described for various regions of the United States. The Third NCA is currently in draft form and is scheduled for issuance in early 2014.

Climate change has modified the environment in the area around the proposed project and is projected to cause additional changes to the project area. The Second and draft Third NCAs identifies climate change impacts that have occurred along coastal regions in the continental Northeast and Canadian Maritimes. Previous impacts on historical baseline climate and as well as projected climate change impacts that could affect the project area are identified below:

- Average temperatures have risen about 2° F since 1970 and are projected to increase another 2 to 4°F during this century;
- Winters in the Northeast are projected to be much shorter with fewer cold days and more precipitation with the length of the winter snow season would be cut in half;
- Cities that today experience few days above 100°F each summer would average 20 such days per summer;
- Short-term (one- to three-month) droughts are projected to occur as frequently as once each summer;
- Hot summer conditions would arrive three weeks earlier and last three weeks longer into the fall;
- Agricultural production, including dairy, fruit, and maple syrup, are likely to be adversely affected as favorable climates shift;
- The oceans are currently absorbing about a quarter of the CO2 emitted to the atmosphere annually and are becoming more acidic as a result, leading to concerns about potential impacts on marine ecosystems;
- Increasing risk from sea-level rise and storm surge;
- Coastal waters have risen about 2°F in several regions and are likely to continue to arm as much as 4 to 8°F this century with concomitant impacts on fisheries;

- Infrastructure will be increasingly compromised by climate-related hazards, including sea level rise and coastal flooding, and intense precipitation events; and
- Coastal water warming may lead to the transport of invasive species through BWE during ship transit.

As identified in section 4.11.1, the project would be required to obtain a Title V Part 70 operating permit to limit emissions of GHG from the Projects. Although the Project emissions would contribute to the overall amount of atmospheric GHG, it is impossible to quantify the impacts that the emissions of GHG from construction and operation of the Project would have on climate change.

### 4.13.8 Cultural Resources

Downeast continues to consult with the SHPO and Passamaquoddy Tribe regarding potential project impacts on cultural resources, traditional cultural properties, and religious interests of the Passamaquoddy Tribe, including possible impacts of LNG marine traffic on traditional waters and fisheries. We have recommended in section 4.10.4 of this EIS that Downeast complete such consultations prior to construction, so that the FERC and other cooperating agencies would be in compliance with the NHPA. In addition, the Coast Guard's WSR recommends written verification that the Passamaquoddy Nation is satisfied with the resolution of its concerns about tribal resources in the waterway and the associated safety and security interests. Because no historic properties have been identified to date that would be adversely effected by Downeast's proposal, that project would not be adding incrementally to cumulative regional impacts on cultural resources which are listed or eligible for listing on the NRHP.

Non-federal actions would need to comply with any mitigation measures required by the state of Maine. Any other projects with a federal nexus would have to adhere to section 106 of the NHPA, and follow the regulatory requirements of 36 CFR 800. Under those regulations, the lead federal agency, in consultation with the SHPO, would have to identify historic properties in the APE, assess potential project effects, and resolve adverse effects through an agreement document that outlines a treatment plan. The NHPA and its implementing regulations ensure that projects that require a federal permit, license, or approval would not have significant cumulative impacts on historic properties.

### 4.13.9 Socioeconomics and Environmental Justice

During construction, the other projects listed in table 4.13-1 could compete with the Downeast LNG Project for construction resources (labor, local services, equipment, and materials), if they were under construction concurrently. Several of the projects in Washington County are dissimilar in nature from the proposed Downeast LNG Project and most have already been constructed. Therefore, significant cumulative impacts on construction resources are unlikely.

Based on available information, operation of the projects listed in table 4.13-1 that involve marine transportation could have cumulative impacts on commercial fishing in the area as a result of the increased marine traffic. The Downeast LNG Project would result in an estimated 60 LNG vessel calls per year. LNG vessels would follow a circuitous route through both United States and Canadian waters, virtually the same route as currently used by all deep-draft vessels servicing Passamaquoddy Bay port areas, including the ports of Bayside, New Brunswick, and

Eastport, Maine. These ports receive on average an estimated 120 deep-draft vessel arrivals per year. If the Downeast LNG Project was built, the associated LNG vessel traffic would result in roughly a 50 percent increase in anticipated deep-draft vessel traffic. The Coast Guard-recommended safety and security zones around LNG vessels during passage through Head Harbour Passage, Western Passage, and Passamaquoddy Bay would be in place for each of the LNG vessel trips. Coordination with the Coast Guard and other waterway and port authorities in the area, and advance notice of the arrival and departure of LNG vessels, along with the implementation of vessel traffic management practices recommended by the Coast Guard's WSR, would reduce impacts on other marine traffic, both commercial and recreational.

Downeast has also developed a Fishermen's Communication, Coordination, and Compensation Plan to reduce any impacts on commercial fishing. It is expected that the other marine projects listed in table 4.13-1 would strive to avoid, minimize, or mitigate for impacts on commercial fisheries.

If other construction or pipeline projects were to occur during the construction phase of the Downeast LNG Project, tight labor markets could result, which in turn could lead to more non-local workers entering the local labor force for the duration of the construction. Given declining populations in recent years and the available capacity in local housing and schools, this could provide a beneficial cumulative impact on the local economy, with insignificant cumulative adverse impacts.

### 4.13.10 Land Use, Recreation, and Visual Resources

Construction and operation of the Downeast LNG Project would result in temporary and permanent changes in land use. The other projects listed in table 4.13-1 could also result in similar types of impacts on land uses. The total acreage permanently converted to industrial land use as a result of construction and operation of the projects listed in table 4.13-1 is not known. This conversion to industrial use would have a minor cumulative impact on land use in the region.

Recreational activities, including fishing and boating, occur along the shores of Passamaquoddy Bay and within its waters. The projects listed in table 4.13-1 could have a cumulative negative impact on these recreational activities, primarily during the period of active construction of terminals and offshore facilities. The cumulative impacts on recreation from construction activities would be short-term and would not be significant.

When operational, Downeast expects to receive about 60 LNG vessels annually. In addition, the Port of Eastport is proposing expanded facilities that could result in an increase in shipping traffic. In addition, repair and maintenance of the tidal energy projects close to or within the waterway would infrequently add barges and other maintenance apparatus (e.g., underwater remote-operated vehicles) to the waterway. Nevertheless, the cumulative impacts on recreational fishing and boating from the projects in the area would be insignificant. A limited number of small crafts use the vessel channel where marine traffic would be concentrated, and they would receive advance notice of an LNG vessel transit through established broadcasts to mariners. The safety and security zones, and other vessel traffic practices, recommended by the WSR may limit recreational and other boat traffic in the vicinity of LNG vessels. However, recreational fishing is very limited in Passamaquoddy Bay, most likely because of the large extent of the intertidal area exposed at low-water and the strong tidal currents.

Land use and recreational activities could also be affected by the security zones established around the Downeast LNG terminal, trestle, and berthing pier. The exact area of prohibited activities near the project has not yet been determined. It would be included by Downeast in its Operations and Emergency Manual and Facility Security Plan, which are required by federal law and must be submitted to the COTP Sector Northern New England for review and approval at least six months before the terminal is operational. While the exact security zone has not been established, it should not be a significant impact based on the limited land use and recreational activity near the terminal site.

The Downeast LNG Project and other projects listed in table 4.13-1 would have some visual impact on the immediate surroundings. Downeast has incorporated design specifications (described in section 4.7.4 of this EIS) to minimize the visual impact of its facilities. The area already has vessel traffic through the nearby waters, and the addition of up to about 60 vessels per year would not be a significant visual impact. Depending on the final lighting designs for the proposed Downeast LNG terminal, there could be increased outdoor lighting on the night sky. This should be minimized by the type and amount of lighting utilized and approved by the COTP Northern New England in the approval of the Facility Security Plan. Overall, the cumulative visual impacts of the Downeast LNG and other projects would not be significant. For the sendout pipeline, the construction area would be restored to pre-construction contours, as nearly as possible, and revegetated. There would be a permanent visual impact along the pipeline rights-of-way in the areas where forest land is cleared and the permanent rights-of-way are maintained in an herbaceous state. However, once revegetation is complete, these alterations of the landscape would be insignificant with the exception of forested areas, which would be maintained as non-forest vegetation on the permanent operational rights-of-way.

### 4.13.11 Safety

We have received comments regarding the cumulative safety impacts of the LNG and pipeline projects listed in table 4.13-1. These safety issues concern potential release of LNG from the terminals and/or LNG vessels, security along the LNG vessel transit routes, and potential pipeline accidents along the sendout pipeline route. Since issuance of the draft EIS, the Quoddy Bay, Calais, and Maple LNG Projects are no longer proposed; therefore, they were removed from the cumulative impacts analysis. The existing Canaport LNG Project is approximately 60 miles from the proposed Downeast LNG terminal site. Given the distance between project facilities, there would be no overlap of the areas that could be affected by a potential accident.

Impacts from an accidental release of LNG from the Downeast LNG terminal and/or LNG vessels are discussed in detail in section 4.12 and are related to vapor dispersion and thermal radiation. As discussed in section 4.12, research conducted by Sandia and the subsequent report entitled *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill over Water* have provided guidance to the Coast Guard relative to the impacts of an LNG spill. The Coast Guard used the criteria developed by Sandia (Sandia 2004) to define the outer limits of the hazard zones, referred to as Zones of Concern, for assessing potential risks.

As discussed above, the Coast Guard's WSR recommends vessel traffic operating practices, which includes safety and security zones around LNG vessels transiting to and from the LNG terminal and vessel speed restrictions, among other parameters. This may limit recreational and commercial traffic within the vicinity of the LNG vessels during transit.

Pipeline safety is discussed in detail in section 4.12 using existing pipeline operational data. The available data shows that natural gas pipeline continues to be a safe, reliable means of energy transportation and, therefore, there would be no adverse cumulative safety impacts from the proposed pipeline facilities for the projects listed in table 4.13-1.

### 4.13.12 Indirect Impacts

Commenters have asked that we discuss the foreseeable indirect consequences to the environment resulting from the proposed Downeast LNG Project. According to 40 CFR 1508.8(b), indirect effects are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable. We have assumed that the commenters are concerned that authorization of the project could be the initial step in widespread development of industrial and commercial structures or facilities in Washington County, Maine. To assess the potential for this to occur, we evaluated four potential factors that could lead to such development: secondary economic activity, economic clustering (or agglomeration), precedent, and entrepreneurial innovation.

#### Secondary Economic Activity

Secondary economic activity is associated with the re-spending of project-related dollars. This includes indirect effects (changes in sales, income, or employment within backward-linked industries that supply firms participating directly in a project) and induced effects (increased sales from households spending income earned via a project). An example might include increased demand for security officers associated with the LNG terminal.

If implementation of the proposed Downeast LNG Project resulted in a substantial amount of secondary economic activity, it could indicate the potential for industrialization. As reported in section 4.8, some additional jobs may result from secondary activities associated with construction and the purchases made by non-local workers for food, clothing, gasoline, and entertainment. This secondary job creation would likely be limited, but beneficial. Using assumptions that maximize potential secondary activity, a total average of 569 jobs, with a peak of about 650 jobs, could be associated with secondary economic activity during the construction period. Downeast also estimated that approximately 320 pipeline workers would be required during a nine-month pipeline construction period. The Downeast LNG terminal operations would support a total of 187 jobs in Washington County over the terminal's lifecycle. Given the short-term increase in jobs during the construction phase and the limited number of permanent jobs expected during operation, the minimal level of secondary income and employment impacts, although beneficial, does not indicate a significant potential for industrialization.

#### Economic Clustering

Economic clustering (often termed "economic agglomeration") occurs when industries and businesses achieve cost savings by locating in proximity to one another or to essential infrastructure. For example, shipping and packaging facilities may cluster near ports because reduced transportation costs impart competitive advantage. A study conducted by the University of Maine found that terminal construction would support an estimated 375 jobs in Washington County in each year of the construction project. These workers would receive an estimated $15.3 million in income per year. An impact of 375 new jobs would be equivalent to 2.67 percent of total employment in Washington County as of 2000. The study used an employment multiplier of 2.04, meaning that each Washington County worker employed on the construction project would support an additional 1.04 workers within the county. However, it should be noted that the U.S. Bureau of Economic Analysis calculated an employment multiplier of 1.44 for Washington County, which would result in a smaller number of indirect jobs and lesser amounts of secondary income than predicted by the University of Maine study. By either calculation, the creation of secondary jobs and income, while beneficial to the County, would not be sufficient to create a significant agglomeration of businesses in proximity to the LNG terminal or to one another.

Construction of the Downeast LNG Project is not likely to cause an adjacent industrial build-up. The project would facilitate supply of natural gas to the region. It is not proposing to be a local industrial distributor of natural gas. Heavy industry would not have any supply incentive to collocate near the Downeast LNG terminal; thus, there would be no economic clustering of heavy industry adjacent to the terminal.

**Precedent**

There are existing industrial and commercial uses in and around Passamoquody Bay and Washington County, including commercial fishing, tourism, salmon aquaculture, tidal energy, and commercial ports. Approval of the Downeast LNG Project would result in another industrial/commercial use of the Bay. The Downeast LNG Project would not set a precedent for industrial/commercial use in the area.

**Entrepreneurial Innovation**

The process of permitting, constructing, and operating the proposed project could spur others to identify or invent potential commercial/industrial applications that would derive cost benefits by being located in the area. By definition, innovation and the motivation behind it is difficult to predict. However, it is reasonable to assume that construction and operation of the proposed project could lead to innovations, and it is possible that an entrepreneur could be spurred to identify a new industrial application that could be appropriate for Washington County. If that were to occur, the new application would still require review by the appropriate federal, state, and/or local agencies to determine whether the project is consistent with environmental and other regulatory requirements. Projects that do not meet regulatory requirements would not receive permits from the reviewing agencies.

**Summary**

As discussed above, secondary economic activity associated with the Downeast LNG Project would be minor and would not be sufficient to stimulate additional industrial growth. With respect to economic clustering, we were unable to identify situations where the creation of secondary jobs and income would be sufficient to result in the establishment of a cluster of businesses near the proposed project. The Downeast LNG Project would not set a precedent for industrial/commercial use in the area. Although we recognize that the project could spur entrepreneurial innovation, any new development in the area would face the same regulatory review as the project to determine impacts and viability.

### 4.13.13 Conclusions About Cumulative Impacts

A determination of significance of the cumulative impacts for a specific resource is problematic because well-defined threshold values are typically undetermined. However, the majority of impacts we have identified for the proposed Downeast LNG Project would be temporary and minor. Consequently, their addition to other reasonably foreseeable impacts in the region does not result in a significant increase in permanent impacts.

There would be several notable permanent impacts, however. The permanent conversion of forest land communities to an herbaceous community along the proposed sendout pipeline in combination with other past, present, or reasonably foreseeable future projects, could potentially fragment some wildlife habitat. Additionally, the Downeast LNG Project, together with the other projects in the area, would contribute to increased vessel traffic along the vessel channel. Although the Downeast LNG Project and other projects would result in the degradation of some wetland habitats, compensatory mitigation programs for each of these projects would be designed to provide a net benefit to the ecosystem.

As many of the project stakeholders and community residents have noted, the Downeast LNG Project, together with the other projects in the area, would cumulatively benefit the local economy through job creation and wages, tax revenues, and by providing a new source of competitively priced natural gas. A further effect would be a small increase in the area's population. Adverse indirect impacts would be insignificant.

# 5.0 CONCLUSIONS AND RECOMMENDATIONS

## 5.1 SUMMARY OF THE STAFF'S ENVIRONMENTAL ANALYSIS

The conclusions and recommendations presented are those of the FERC environmental staff. While our conclusions and recommendations were developed with input from the Coast Guard, COE, DOT, NOAA Fisheries, EPA, and Maine DEP as cooperating agencies, each of these agencies may present its own conclusions and recommendations when it has completed its review of the project.

The primary impacts associated with construction and operation of the Downeast LNG Project include the permanent conversion of forest land communities to an herbaceous community along the proposed sendout pipeline; increased ship traffic along the ship channels, which could potentially affect marine mammals (e.g., vessel collisions, acoustic harassment, physical harassment, and exposure to pollutants and marine debris); permanent loss of forested wetlands; and alteration of visual character to viewers within close proximity of the terminal. We have determined that construction and operation of the Downeast LNG Project would result in some adverse environmental impacts. However, most of these impacts would be reduced to less-than-significant levels with the implementation of Downeast’s proposed mitigation measures and the additional measures we recommend in this EIS. Our assessment is the product of an interdisciplinary review by the FERC staff and our cooperating federal and state agencies. Our assessment is based on the analysis and critical review of information compiled from field investigations by the FERC staff; literature research; alternatives analysis; comments from federal, state, and local agencies; input from public groups and individual citizens; and information provided by Downeast and its technical consultants.

As part of our analysis, we developed specific mitigation measures that would appropriately and reasonably avoid, minimize, and/or mitigate for environmental impacts resulting from construction and operation of the proposed project. These measures would further reduce the environmental impact that otherwise would result from implementation of the project, and we recommend that these measures be attached as conditions to any authorization issued by the Commission. We conclude that, if the project is implemented as planned with the identified and recommended mitigation measures during design, construction, and operation, it would be an environmentally acceptable action.

The conclusions and recommendations presented here pertain to the Downeast LNG Project facilities. Downeast would coordinate with EMEC on the use of EMEC’s transmission line right-of-way for a portion of Downeast’s pipeline right-of-way; therefore, we are recommending that Downeast not begin construction of the pipeline from MP 17.7 to 27.2 until updated alignment sheets, developed in coordination with EMEC, are filed with the Secretary.

### 5.1.1 Geology

No significant impacts on surficial geology, bedrock, mineral resources, or paleontological resources would occur along the waterway from the increase in LNG marine traffic. There is a low but steady rate of seismic activity in Maine where the marine transit route is located. However, we do not expect seismicity, soil liquefaction, or subsidence to affect LNG marine traffic using the waterway. The shoreline of the waterway for LNG marine traffic is not considered susceptible to hazardous landslides.

Construction and operation of the project would have minimal impact on geological resources in the area, and the potential for significant geologic hazards or other natural events to significantly impact the project is low. The existing topography at the onshore portion of the LNG terminal site would be permanently changed to accommodate the storage tanks and terminal facilities; however, topographic contours and drainage conditions disturbed during construction of the sendout pipeline would be restored as closely as possible to preconstruction conditions. Some blasting is anticipated at the terminal site (for the LNG storage tanks and spill containment basins) and along the pipeline, but appropriate precautions would be taken to protect dwellings and water supplies. No mineral resources were identified at or adjacent to the LNG terminal. Three former borrow pits are located more than 0.5 mile away from the pipeline right-of-way; however, these would not be impacted by construction or operation of the sendout pipeline. Paleontological resources are not anticipated to be encountered in the area of the terminal or sendout pipeline. Soil liquefaction, subsidence, and landslides are not expected to occur in the project area. Flash flooding is possible at stream crossings along the sendout pipeline; however, the pipeline crossings would be designed and protected to mitigate against damage from flooding. All of the structures at the LNG terminal site are located at an elevation high enough to avoid projected future increases in sea level.

The potential for seismicity associated with surficial fault displacement does not represent a significant risk to the proposed project. Additional geotechnical investigations of the site and further details regarding Downeast's proposed seismic design criteria for foundations and critical structures are necessary to adequately design the terminal facilities. We are recommending that Downeast file design and construction details stamped and sealed by the professional engineer of record.

### 5.1.2 Soils and Sediments

No significant impacts on soils or sediments would occur along the waterway resulting from normal operation of LNG traffic. The waterway is an existing shipping channel with large vessel traffic and there are no sensitive soils along the shoreline that are prone to erosion; therefore, LNG vessel traffic would not cause an increase in shoreline erosion.

Of the approximate 80 acres of land at the terminal location, construction and operation of the LNG terminal would permanently disturb approximately 26.9 acres of soils classified as farmland of statewide importance and susceptible to compaction; and 19.7 acres of "potentially highly erodible" soils. Some low level sediment contamination was identified in the general area of proposed pier construction activities; however, Downeast would not perform any dredging, trenching, or substrate-disturbing activity other than pile installation and the pile driving operation using a vibratory hammer is expected to cause limited resuspension of sediments. Construction vessels may create minor amounts of sediment suspension due to propeller wash, but given the tidal fluctuations and the deep water in this area this disturbance would be minor and temporary. In addition, the use of over-top construction methods in shallow waters and jack-up barges in deeper waters would minimize construction vessel activity that could result in the resuspension of sediments. Because of the use of these construction methods, construction and operation of the proposed project would not result in any significant impacts on water quality within Mill Cove, the St. Croix River, or Passamaquoddy Bay.

Construction of the sendout pipeline would impact approximately 7.2 acres of land considered prime farmland and 38.9 acres of land classified as farmland of statewide importance. These areas are not used for active agriculture and would be restored to preconstruction conditions; therefore, impacts on farmland and agriculture would not be significant. Construction of the sendout pipeline would temporarily impact soils with high or potentially high erosion potential, high compaction potential, poor revegetation potential, and hydric conditions. To minimize and mitigate for adverse impacts due to soil erosion in the area of the LNG terminal and sendout pipeline, Downeast would implement its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*.

### 5.1.3 Water Resources

#### 5.1.3.1 Groundwater

Construction and operation of the project would have no significant impact on groundwater quality and quantity. Minor amounts of groundwater would be used during construction of the LNG terminal for miscellaneous construction purposes (e.g., dust suppression) and to initially fill the vaporizers prior to SCV system start-up. During operations, Downeast would utilize groundwater wells as a potable water source for the LNG terminal. Based upon sampling and analysis of monitoring wells, an adequate and acceptable water supply exists in the bedrock beneath the LNG terminal for proposed construction and operational water requirements.

Dewatering would likely be necessary during construction/excavation of the tank foundations and spill containment basins. Downeast would prepare and file with FERC a detailed site grading plan, that addresses control and collection of groundwater prior to construction.

The sendout pipeline route crosses designated significant sand and gravel aquifers from MP 13.8 to MP 14.1, MP 25.4 to MP 25.5, and MP 28.4 to 29.0. The Baileyville WPA would be traversed by the proposed sendout pipeline route between MP 25.4 and 25.6, and between MP 28.6 and MP 28.7. There are two wells associated with the WPA operated by the BUD; however, neither is within 150 feet of the proposed sendout pipeline route. Downeast has proposed an HDD in the area of the Baileyville WPA to minimize potential surface impacts. State and local officials expressed concerns that the HDD proposed in this area could alter groundwater flow patterns and potentially cause contaminated groundwater associated with a nearby landfill to migrate towards the Baileyville WPA. Because of the groundwater flow direction in this area, and the distance between the abandoned landfill and the proposed pipeline, we conclude that the installation and presence of the pipeline in this area would not impact the WPA. Downeast has made a commitment to take special care in maintaining good spill prevention and control practices during pipeline installation and maintenance in areas overlying the significant sand and gravel aquifers. Based on these assurances, the Maine CDC Drinking Water Program indicated that the "current pipeline alignment does not appear to pose a significant threat to the public water supply." We concur.

Downeast has not completed surveying the entire proposed pipeline route for private wells. We are recommending that Downeast file the location of all private wells and springs within 150 feet of construction activities and conduct pre- and post-construction monitoring of well yield and water quality for these wells. In the event a water well or system is damaged as a result of construction, we are recommending that Downeast arrange for a temporary source of potable water, and provide for the repair of the well or replacement of the water supply.

The greatest potential for impact on groundwater would be from spills, leaks, or other releases of hazardous substances during construction or operation. Downeast has developed a SPCC Plan to address potential spills of fuel, lubricants, and other hazardous materials. We have reviewed the SPCC Plan and believe it adequately addresses potential spills and would minimize or eliminate the potential for adverse impacts on groundwater resources.

#### 5.1.3.2 Surface Water

During operations, LNG vessel activity would have limited potential for impacts on surface waters. No ballast water would be discharged from LNG vessels along the waterway or at the terminal. However, LNG vessels would take on ballast water to maintain vessel trim and stability, and keep the vessel's hull within acceptable stress levels as they offload their cargo. The amount of ballast water required by each LNG vessel would vary according to its size and weather conditions. The largest vessel that would be accommodated at the LNG terminal (165,000 $m^3$) would require about 17.11 million gallons of water for ballast. This water withdrawal would constitute a minor but long-term impact on water resources of Passamaquoddy Bay. LNG vessels would comply with the Coast Guard's mandatory ballast water management and exchange standards.

LNG vessels would also require the intake of cooling water during transit along the waterway and while docked at the terminal berth. Over a 21-hour period, a 165,000 $m^3$ LNG vessel would require a maximum of about 55.5 million gallons of water to support engine cooling while at the pier. Discharge of the cooling water would raise the water temperature at the discharge location. However, Downeast's numerical modeling of the mixing zone indicates that the discharge plume would be relatively minor and reach near ambient conditions at approximately 15 to 30 meters from the point of discharge. Further, due to the comparatively small volume of this water in relation to the flow of Passamaquoddy Bay (estimated to be about 0.001 percent of the quantity of water that flows in and out of Passamaquoddy Bay during one tidal cycle), and the swift currents that would cause rapid mixing, we find that there would be no discernable impact on the water quality of Passamaquoddy Bay from cooling water discharge activities.

Accidental spills or releases of hazardous materials could also impact water quality along the waterway. Through compliance with MARPOL and VGP permit requirements, water quality effects associated with the discharge of graywater, blackwater, or potential accidental releases would be effectively minimized. During operations, wakes and propeller wash associated with LNG and associated escort vessel activity may cause minor resuspension of bottom sediments and temporary increases in turbidity. Impacts would be localized and would not significantly increase turbidity along the transit corridor.

Construction of the LNG terminal could temporarily adversely affect surface water quality in Mill Cove. The primary effect on water quality would be minor increases in suspended solids in the water column in the vicinity of the pile installation activities and from marine construction vessels. Due to the currents and significant tidal volume exchange, any localized water quality impacts would quickly return to preconstruction conditions. There is a potential for the inadvertent release of fuel to the waters of Mill Cove and Passamaquoddy Bay from vessels working to construct the offshore portions of the LNG terminal. To minimize the likelihood of spills as well as to minimize environmental impacts in the event that a spill was to occur during construction or operation of the terminal, we are recommending that Downeast develop and file a Marine SPCC Plan for our review and approval, prior to construction of the LNG terminal.

Operational impacts of the LNG terminal would include generation of freshwater effluent from the SCV technology used to process the LNG. The SCVs would produce excess water at a rate of 85 gpm when the LNG terminal is operating at normal sendout capacity and up to 109 gpm during peak capacity. Downeast proposes to use recovered SCV water to supply its firewater system and sell surplus SCV water to an independent party for offsite use, yet to be identified. To ensure impacts are minimized in the event that the SCV water cannot be sold, we are recommending that Downeast file a final plan for the discharge of excess SCV water for our review and approval, prior to construction of the LNG terminal facilities. The plan should include discharge locations, rates, mitigation measures, and copies of applicable permit applications.

Hydrostatic testing of each LNG storage tank would involve filling the inner tank with approximately 28 million gallons of water, principally obtained from Passamaquoddy Bay. Test water would be discharged into Passamaquoddy Bay using an aeration type energy dissipater to prevent potential erosion and scouring of the bottom sediments. To minimize potential water quality impacts, all test water would be analyzed for chemical composition, treated if necessary, and discharged at a rate determined in the Maine PDES permit issued by the Maine DEP.

Other potential impacts on water resources involve the uptake of water from Passamaquoddy Bay for backup emergency firewater pumps. This would only occur in an emergency situation and would constitute a minor impact on water resources given the immense tidal flow of Passamaquoddy Bay, with an estimated 70 billion cubic feet of water entering and leaving twice daily on the turn of the tide.

The proposed sendout pipeline would cross 22 surface waterbodies. Activities that could affect surface waters include clearing, grading, trenching, blasting, backfilling, and right-of-way maintenance. Downeast proposes to cross 9 of the 22 waterbodies using the HDD crossing method. We have included Downeast's site-specific HDD plans for each proposed HDD crossing in Appendix E of the EIS. The measures detailed in Downeast's Plan, Procedures and *Soil Erosion and Sediment Control Guidelines* and applicable permits would minimize both short- and long-term impacts on water resources.

One of the largest HDD crossings proposed by Downeast is the 6,621-foot-long crossing of the St. Croix River and Magurrewock Stream Outlet between MP 14.1 and MP 15.3. Downeast has evaluated the available geotechnical information relative to the subsurface conditions in the St. Croix River, and filed a site-specific construction diagram, and a proposed alternate route should the HDD fail. Downeast has indicated that it would file a geotechnical analysis of the HDD location prior to requesting authorization to commence construction of its terminal or pipeline facilities and that the St. Croix HDD would be the first portion of the sendout pipeline constructed. Prior to being placed into service, the sendout pipeline would be hydrostatically tested to DOT standards, as listed in 49 CFR 192. Approximately 6.1 million gallons of water would be obtained from the BUD for hydrostatic testing of the entire sendout pipeline.

Following testing, the hydrostatic test water would be discharged to an unnamed creek at MP 17.5 or to the BUD sewer system. Discharges of hydrostatic test water would require permitting from the Maine DEP in compliance with the CWA. The appropriate Section 401 Water Quality Certification and Section 404 permit must also be obtained prior to discharge of hydrostatic test water into surface waterbodies.

### 5.1.4 Wetlands and Vegetation

#### 5.1.4.1 Wetlands

There would be no impacts on subtidal, intertidal, or palustrine wetlands as a result of normal LNG vessel transit. Construction and operation of the pier pilings would directly disturb 0.1 acre of wetland. Indirect impacts on wetlands include shading and potentially altered hydrodynamic processes in the vicinity of the pier. In addition, approximately 9 acres of forested and scrub-shrub freshwater wetlands would be permanently affected by the onshore LNG terminal facilities. To mitigate for the unavoidable wetland alterations associated with the proposed terminal, Downeast is proposing a combination of preservation, enhancement, and restoration at off-site locations. In order to ensure that adequate wetland compensation is provided to the satisfaction of the relevant agencies, we are recommending that Downeast continue consultation with the COE, EPA, Maine DIFW, and Maine DEP to finalize its wetland compensation plan, and file the final plan prior to construction.

Approximately 21.6 acres of wetlands would be affected during construction of the sendout pipeline, of which approximately 11.7 acres would be affected by maintenance within a 30-foot-wide portion of the permanent right-of-way during operation. To minimize the extent and duration of wetland impacts, Downeast would use a 55 to 65-foot-wide construction right-of-way and would implement its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines*. Following restoration, Downeast would monitor the success of wetland revegetation annually for until wetland vegetation is successful. Vegetation maintenance would not be conducted over the full width of the maintained portion of the permanent right-of-way in wetlands. A 10-foot-wide area directly over the pipeline would be mowed on an annual basis and shrubs and trees may be selectively removed within 15 feet of the pipeline. Forested wetlands within the permanent right-of-way would be converted to herbaceous and scrub shrub wetland types.

Downeast identified 43 vernal pools, of which 10 were determined to meet the criteria necessary to be classified as SVP. To minimize impacts on vernal pools, Downeast would use the guidelines approved by FERC, the COE, and the Maine DEP for the M&NE Phase II Pipeline Project. Additionally, Downeast would follow the *Best Management Practices, Conserving Pool-Breeding Amphibians in Residential and Commercial Developments in the Northeastern United States* (Calhoun and Klemens 2002) for development of site-specific construction activity and restoration plans. Post-construction restoration of the vernal pool areas would include replication of the vernal pool depression using the same soils excavated, as well as replanting as much of the upland habitat buffer as possible while maintaining access to the right-of-way. The construction right-of-way width would be reduced to 55 feet through vernal pool areas. The duration of disturbance would be short-term, generally 24 to 48 hours. Sedimentation of the vernal pool areas would be minimized through use of erosion control devices.

A majority of the impacts on wetlands resulting from construction and operation of the proposed sendout pipeline would be temporary. Based on communication with the COE and the Maine DEP, Downeast does not anticipate providing mitigation for the temporary impacts associated with the sendout pipeline installation.

### 5.1.4.2 Marine Vegetation

There would be no impact on marine vegetation as a result of normal LNG marine traffic. Eelgrass mapping completed by the Maine DMR in 2010 identified eelgrass within Mill Cove that was not present during previous mapping efforts in the 1990s. However, the mapped eelgrass occurs in shallow water and at the closest point would be approximately 2,500 feet from the end of the pier where LNG vessels and support tugs would operate. Because of this distance, operation of LNG vessels and support vessels within the waterway would not impact mapped eelgrass.

Terminal construction activities that may affect marine vegetation include sediment disturbance due to piling installation and the anchoring of barges. Development of the pier and berthing facility would result in the permanent loss of a small quantity of algae as a result of pile installation and shading; however, the footprint of the pilings is relatively small, and the height and orientation of the pier would create a very limited shadow effect. The proposed pier would cross about 350 feet of mapped eelgrass. In this area eelgrass could be directly impacted by placement of piles, temporary disturbance of bottom sediments during pile installation, and from shading during Project operation. The actual area of impact would need to be determined based on site-specific survey to verify the presence and extent of eelgrass in the area of the proposed pier. We are recommending that Downeast conduct project-specific eelgrass mapping to determine the presence and extent of eelgrass that would be affected by the pier, and that results of the eelgrass mapping be incorporated into compensatory mitigation planning, as needed.

The pilings of the pier would provide increased surface areas suitable for supporting shade-tolerant algae species. During the construction and operation of the terminal, marine water withdrawals for hydrostatic testing, fire suppression systems testing, and ship ballast and hoteling may also have short-term and localized impacts on phytoplankton. Specifically, cooling water uptake by the LNG vessels would impact phytoplankton located proximal to the vessel's intake. However, any mortality would be replaced through tidal action from the larger phytoplankton population within the Passamaquoddy Bay.

### 5.1.4.3 Terrestrial Vegetation

Island and shoreline vegetation along the waterway for LNG marine traffic is generally described as wooded with ledge rock outcrops. During normal LNG transit operations there would be no adverse impacts on these habitats.

Development of the 80 acre terminal site would result in the permanent clearing of approximately 47 acres of land, including 9 acres of wetland and 38 acres of forest. Downeast proposed to leave the remaining 33 acres undeveloped as a buffer. However, Downeast did not account for the forested areas in its hazard analyses. Therefore, in section 4.12.5, we recommended that Downeast certify that all trees would be removed from the area between the vapor fences and the shoreline or demonstrate that the spacing of the trees, and any vegetation management plan, would prevent congested areas that could produce offsite overpressures above

1 psi. An additional 8 acres of grassland located offsite would be temporarily disturbed during construction of the LNG terminal for use as ATWS.

Construction of the sendout pipeline and associated valve station would affect an estimated 175.4 acres of forest, of which approximately 112.2 acres would be permanently converted into a non-forested vegetation community. The sendout pipeline would also affect an estimated 31.3 acres of open land (which includes developed land, agricultural land, and grassland), of which approximately 18.9 acres would be permanently maintained right-of-way. The widening and improvement of access roads would impact approximately 10 acres of land, of which 0.5 acre is forested and 9.5 acres are developed land. Staging areas would temporarily impact approximately 13.5 acres of forest and 5.2 acres of open habitats.

Downeast located the proposed pipeline right-of-way immediately adjacent to existing rights-of-way to the greatest extent practical to minimize forest habitat loss and fragmentation. Upon completion of construction, the right-of-way would be revegetated according to seed mixtures recommended by the NRCS. A permanent right-of-way would be maintained to permit access for routine inspection, maintenance, and emergency repairs. In uplands, the entire 50-foot-wide permanent right-of-way may be cleared every three years. A 10-foot-wide area directly over the pipeline would be mowed on an annual basis. Construction, revegetation, and maintenance procedures would follow Downeast's Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines* to ensure successful restoration of the right-of-way.

#### 5.1.4.4 Unique or Invasive Plant Communities

During normal LNG marine transit operations, there would be no adverse impacts on unique plant communities. No rare or invasive plant species are located at the site of the proposed LNG terminal. Two invasive plant species, purple loosestrife and alder-buckthorn, were identified in several places along the pipeline route. During installation, operation, and maintenance of the sendout pipeline, Downeast would employ measures in its *Soil Erosion and Sediment Control Guidelines* to prevent introducing new invasive species and avoid encouraging the spread of undesirable species already present.

### 5.1.5 Wildlife and Aquatic Resources

#### 5.1.5.1 Terrestrial Wildlife

Impacts on coastal and marine avifauna resulting from construction and operation of the project would include temporary alteration and permanent loss of habitat. Wildlife habitats crossed by the project include waterfowl and wading bird habitat in coastal and inland locations, shorebird feeding and roosting areas, vernal pools, mature forested uplands, early successional habitats, agricultural and open lands (which include freshwater wetlands), and forested wetlands.

Significant wildlife habitats occur within and near the waterway for the LNG marine traffic. These include IWWH, TWWH, shorebird nesting, feeding and staging areas, and seabird nesting islands. The primary impact from LNG marine traffic would be harassment (i.e., physical and acoustic) to coastal and marine birds. The long-term effect of bird and vessel collisions would not have measurable consequences to bird populations in the project area. Because known sea and shorebird nesting occurrence near the waterway for LNG marine traffic is low, it is anticipated that normal LNG marine vessel operations would not adversely affect these species.

Impacts on wildlife from the LNG terminal construction and operation would include temporary and permanent loss of habitat in Mill Cove from the pier and onshore from the terminal. To mitigate impacts on nocturnal species, Downeast would strategically locate light fixtures to minimize light pollution beyond the terminal area. In consultation with the Maine DIFW, Downeast has finalized its revised Shorebird Mitigation Plan, in which, among other compensation measures, Downeast has agreed to acquire conservation easements or provide property acquisition funds to offset any potential impacts on shorebird habitat. Short-term impacts, such as disruption and disturbance to wildlife outside of the boundary of the facility would be expected only due to noise and activity associated with construction. Operational noise is not expected to impact wildlife communities outside of the terminal site.

The primary impact on wildlife associated with the sendout pipeline would be clearing of forested habitats and temporary disturbance during construction. Less mobile species may be injured or fatally wounded. Short-term direct effects to terrestrial mammals and breeding or migrating waterbirds would occur during construction of the sendout pipeline in the form of increased noise and human presence. Some forested habitats would be permanently converted to open or shrubland habitats as a result of vegetation maintenance during operation. Due to the amount of significant wildlife habitat that would be disturbed by the proposed project, the Maine DEP requested compensation from Downeast. Downeast developed, in consultation with the Maine DEP, Maine DIFW, FWS, COE and EPA, several mitigation alternatives that specifically focus on preserving inland wetlands that contain significant wildlife habitat. Downeast continues to consult with these agencies for approval of a final, comprehensive wetland mitigation plan that addresses coastal and freshwater wetlands, areas used by tidal and inland wading waterfowl, and significant vernal pools. Based on Downeast's proposed avoidance of shorebird wading habitat during sensitive breeding periods, its adherence to protective measures in its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines,* and its agreement to finalize an acceptable wetland mitigation and compensation plan, impacts on wildlife from construction and operation of the proposed project would be limited, and not significant.

The sendout pipeline crosses one DWA twice between MP 16.72 and 16.80, and from MP 16.86 to 17.02, affecting 2.19 acres. During construction of the sendout pipeline, this DWA would not be available to overwintering deer, representing a loss of cover and forage. While much of the affected right-of-way would be allowed to revegetate over time, a portion of the right-of-way would be subject to routine vegetation clearing and represents a permanent loss of DWA habitat. To minimize impacts, Downeast would consult with the Maine DIFW to develop DWA mitigation measures. We are recommending that Downeast complete its consultations and file its final DWA mitigation package prior to pipeline construction.

#### 5.1.5.2 Aquatic Wildlife

Potential impacts on aquatic wildlife that use waters in or near the proposed LNG marine traffic route may include exposure to pollutants from accidental spills and marine debris; impingement and entrainment during cooling water intake; thermal impacts from engine cooling water discharge; and the potential to introduce non-native aquatic species. Through compliance with MARPOL and VGP permit requirements for vessel discharges, water quality effects and associated impacts on aquatic habitats would be effectively minimized.

Impingement and/or entrainment of aquatic organisms (including fish eggs and larvae) would likely occur during transit and while the LNG vessel is at berth as a result of water withdrawals to support vessel operational and ballast requirement. Vessels in transit would be drawing water as they move across deep open waters, and therefore, the potential impact would be transient and not a significant impact on any particular localized aggregation of aquatic organisms. Vessels at berth would withdraw water for engine cooling, hoteling, and ballast. However, given the significant tidal fluctuations and water exchange that occurs in the project area, the high densities of zooplankton and ichthyoplankton, and the comparatively small amount of water withdrawn, there would not be a significant impact on overall community populations and associated fish stocks in the area. NOAA Fisheries has requested that monitoring be considered during operation to evaluate Project effects on zooplankton and ichthyoplankton; however, we believe that Downeast's use of best available scientific data for plankton impacts are adequate to determine impacts. Based on CORMIX modeling, thermal impacts associated with vessel engine cooling water discharges are also expected to be minor and insignificant. Adverse environmental effects associated with the introduction of exotic/invasive/non-native species through ballast water exchange are not expected; ballast water would not be discharged while transiting or unloading cargo at the berth. Through implementation of industry standard and Coast Guard mandatory practices, we conclude that the introduction of non-indigenous attached organisms via ship hulls is also not likely to significantly alter the local biotic community.

Entrainment and impingement of fish and other aquatic organisms could occur during water withdrawals for hydrostatic testing at the LNG terminal. Downeast would minimize entrainment and impingement of fish by regulating the intake rate and by the use of screens on intake hoses.

Aquaculture also occurs in the vicinity of the transit route. The shorelines along most of the transit route in Western Passage and Friar Roads are steep and rocky offering little habitat for soft-shell clams or mussels. Commercial lobster fishing and commercial harvesting of marine worms occur along the proposed transit route. Downeast, in cooperation with the Maine DMR, met with representatives of the local lobster fishery to further define and detail the lobstermen's key concerns and to confirm the individual lobstermen fishing in any areas potentially affected. This information would be used in Downeast's effort to update and revise the original Fishermen Communication, Coordination and Compensation Plan. We are recommending that Downeast file this plan with the Secretary prior to operation of the terminal.

During LNG terminal construction, impacts on aquatic organisms would result from turbidity and sedimentation, acoustic harassment, and displacement from habitats within Mill Cove. Water from Mill Cove would be withdrawn for hydrostatic testing, LNG marine vessel engine cooling, hoteling, and ballasting operations, and fire suppression system testing. Downeast would use screens to prevent entrainment of fish during hydrostatic testing; however, screens would not prevent the impingement and entrainment of plankton and ichthyoplankton, nor are fine screens available for use on LNG marine vessels. Despite estimated losses, we conclude that the impacts on zooplankton, ichthyoplankton, and mysid shrimp would not have a significant effect on overall community populations and associated fish stocks. This conclusion is based on the significant tidal fluctuations and water exchange that occurs in the project area; the high densities of zooplankton and ichthyoplankton; quick recovery times of mysid shrimp that occur in the surrounding Passamaquoddy Bay; and the comparatively small amount of water withdrawn.

Impacts on commercial fisheries at the LNG terminal would occur as a result of pier installation, through the alteration of traditional fishing patterns, specifically lobstering and weir operation. In areas that have been identified as commercial lobster harvesting areas or areas of weir operations that would be disturbed or removed as the result of construction activities, Downeast has agreed to compensate fishermen for any adverse fisheries-related fiscal loss.

Underwater noise during terminal and pier construction activities would be temporary and long-term noise impacts are not expected to be significant. To mitigate for potential impacts of construction-related noise at the terminal, Downeast has consulted with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss appropriate mitigation measures. Downeast is proposing to implement a number of mitigation measures during all stages of the project that would maximize protection of listed species by either avoiding adverse impacts, or minimizing the potential for adverse impacts from noise.

Downeast proposes to cross streams along the sendout pipeline primarily using dam and pump crossing techniques. In the event that dam and pump crossings are not practicable at these locations, an open-cut crossing technique may be applied. Impacts on water quality and associated aquatic habitats in the sendout pipeline right-of-way would include sedimentation, turbidity, altered water temperatures and dissolved oxygen levels, and introduction of contaminants, all of which can affect the ability of aquatic life to survive and reproduce. Impacts would also include the physical disturbance or destruction of instream cover due to trenching and removal of riparian vegetation. Construction activities could also result in blockage of fish migrations and interruption of spawning activities.

Downeast's stream habitat surveys have confirmed that five stream crossings are riffle and pool complexes that meet the COE criteria as special aquatic sites. Approximately 4,640 square feet of riffle pool habitat would be affected by pipeline construction. Downeast would use the HDD method at two streams with riffle pool habitat and would attempt to avoid installing the pipe in riffle habitats, where possible. Where impacts are unavoidable, Downeast would minimize the discharge of fill to the streams using construction measures outlined in its Plan, Procedures, and *Soil Erosion and Sediment Control Guidelines.*

Although there are no suitable habitat conditions for Atlantic salmon in the streams crossed by the sendout pipeline, Downeast has initiated consultation with Maine ASC to ensure that any potential impact on Atlantic salmon is avoided and/or minimized. Downeast would continue to consult with the appropriate agencies to determine any site-specific timing restrictions for construction. Downeast's Procedures and *Soil Erosion and Sediment Control Guidelines* define a time window for construction in designated cold-water fisheries (June 1 through September 30) and also require that Downeast file a waterbody crossing schedule that identifies when trenching and blasting would occur in each waterbody designated as a coldwater fishery.

Impacts on EFH would include habitat disturbance and alteration associated with the LNG terminal and sendout pipeline. An EFH Assessment was included in Appendix C of the draft EIS and Appendix G of this final EIS. The EFH Assessment includes a detailed description of the life history characteristics and habitat preferences of EFH species and a discussion of the potential for these species to occur within the proposed project's area of potential effect. We requested that NOAA Fisheries consider the draft EIS as notification of initiation of EFH consultation, and request that consultation continue with issuance of this final EIS.

#### 5.1.5.3 Threatened and Endangered Species and Marine Mammals

Informal consultations with the Maine DIFW, FWS, NOAA Fisheries, and Maine Natural Area Program identified special status species and protected marine mammals that potentially occur in the project area. Federally listed whale species including the North Atlantic right, fin, humpback, sei, blue, and sperm whales have been recorded within the proposed waterway for LNG vessels. Another five species of marine mammals under the protection of the MMPA are likely to occur in the waterway including minke whale, gray seal, harbor seal, harbor porpoise, and white-sided dolphin. There are also state-listed species of reptiles, birds, plants, and invertebrates that could be found in the project area.

The primary impacts on federally-protected species associated with the proposed project could include vessel strikes, alteration of prey base, and underwater noise. Currently, about 125 ships per year (primarily bulk carriers and a few cruise ships) pass through the Head Harbour Passage near Campobello Island. The proposed project would increase vessel traffic by about one vessel every five to seven days in the winter and one vessel every eight to ten days in the summer. All LNG marine vessels transiting to the Downeast LNG terminal would be required to comply with NOAA Fisheries regulated practices to protect the right whale. NOAA Fisheries has established regulations to limit vessel speed of ships 65 feet or longer that transit certain management areas along the U.S. east coast (50 CFR Part 224). The regulations limit ship speed to 10 knots or less during times and in areas where relatively high right whale and ship densities overlap and calls for temporary voluntary speed limits in other areas or times when sightings of aggregate whales are confirmed. NOAA Fisheries also prohibits approaching right whales within 500 yards and all other whales within 100 yards when navigational limits permit (50 CFR Part 224). Vessels would also comply with IMO regulations to avoid the Great South Channel ATBA during April through July. In addition, Downeast has indicated its commitment to take the necessary precautions to reduce the risk of injury to right whales and other marine mammals and sea turtles. LNG vessels would follow IMO regulations to report any sightings of right whales and would undertake precautionary measures to avoid any contact with the species. LNG vessel speeds would be limited to 10 knots or less in the transit route and/or in areas where marine mammals are present, under safe navigation rules as recommended by NOAA Fisheries.

Downeast LNG terminal construction and operation crews would also receive environmental training that stresses individual responsibility for marine mammal awareness and reporting. All LNG marine vessel on-board crew members would receive training on marine mammal sighting and reporting, as required by IMO standards. Additionally, the Captains/Pilots of LNG vessels associated with the proposed Downeast LNG Project would be responsible for monitoring communications for sighting reports of the North Atlantic right whale, including local Notice to Mariners, NAVTEX warnings, NOAA Weather Radio, and any other means. Following a received whale sighting warning, LNG vessels would comply with required IMO regulations and federal regulations, and all attempts to avoid contact and reduce the risk of ship strikes to whales would be made. In the event that a vessel strike occurs, the Coast Guard COTP Sector Northern New England Command Center would be notified and the crew would follow procedural guidance.

Downeast has committed to continue its consultation with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss appropriate mitigation measures for threatened and endangered species. This would include procedures for notification of NOAA Fisheries in the event of a whale strike, in addition to the Coast Guard notification described above. Upon completion of ESA consultation and federal and state permitting processes, Downeast would incorporate the final approved construction and mitigation measures into a comprehensive Prevention and Mitigation Manual for use in training of Downeast's construction and operational personnel, which would be filed with FERC.

To estimate the effects of underwater sound propagation produced during construction and operation of the proposed project on marine wildlife, Downeast conducted a comprehensive underwater acoustic modeling analysis. Downeast is consulting with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss appropriate mitigation measures. Noise associated with construction of the proposed project could temporarily limit use of the proposed project area during active construction, but species would return to the area once construction has ceased. Downeast has committed to a number of mitigation measures designed to reduce potential noise impacts on federally-listed species and other resources, and has committed to continue its consultation with the FWS, NOAA Fisheries, and other relevant federal and state agencies to discuss mitigation. We are recommending that Downeast file the manual prior to construction of the LNG terminal facilities. Upon completion of ESA consultation and federal and state permitting processes, Downeast would incorporate the final approved construction and mitigation measures into a comprehensive Prevention and Mitigation Manual for use in training of Downeast's construction and operational personnel.

Increased sediment suspension and turbidity would temporarily increase during construction of the pier but would not adversely affect marine mammals. Water withdrawals for hydrostatic testing, vessel engine cooling, vessel ballasting, vessel hoteling, and fire suppression pump testing would result in the entrainment of phytoplankton and zooplankton. Considering the minimal effect to phytoplankton and zooplankton from entrainment, the loss would have a minimal impact on this prey base for marine mammals.

Downeast would conduct pre-construction clearance surveys at the terminal site for bald eagles, a state-listed species. In the event that confirmed nesting bald eagles are discovered, Downeast would consult with Maine DIFW to establish a comprehensive bald eagle mitigation plan, including seasonal restrictions on construction activities within 0.25 mile of identified nesting areas.

During the aerial surveys of the sendout pipeline route in 2006 and 2008, no active eagle nests were observed within the study corridor or within the 0.25-mile zone on either side. A single historic nest was identified near MP 9.5. Construction activities that have the potential to disturb foraging bald eagles or known roosts would be minimal, localized, and temporary. Downeast has indicated it may also modify the timing of periodic inspections and/or repair of the sendout pipeline to ensure avoidance and minimization of disturbance during sensitive periods if a pipeline section occurs within the protected buffer of any active bald eagle nesting/breeding site.

We prepared a BA that was included with the draft EIS, and a revised BA that was submitted to the FWS and NOAA Fisheries in June 2012. The revised BA is included in Appendix C of this EIS. The BA details the environmental baseline for federally listed species and critical habitat; direct, indirect, interdependent and interrelated, and cumulative effects; and proposed conservation measures. We have determined that the project is not likely to adversely affect the Atlantic salmon, Atlantic sturgeon, shortnose sturgeon, leatherback sea turtle, and six species of whales (North Atlantic right, sei, blue, fin, humpback, and sperm). To ensure compliance with the ESA, we are recommending that Downeast should not begin construction until the staff completes consultation with the FWS and NOAA Fisheries, and Downeast has received written notification from the Director of OEP that construction or use of mitigation may begin.

### 5.1.6 Land Use, Recreation, and Visual Resources

#### 5.1.6.1 Land Use and Recreation

Construction of the Downeast LNG Project would affect a total of 313.2 acres of land. The terminal site primarily is comprised of forested land in various stages of succession. The closest residence is located 125 feet from the proposed LNG terminal boundary. There are no public lands or other designated federal, state, or local recreation areas located on or within 0.25 mile of the LNG terminal site. Only 0.1 acre of submerged land would be directly affected by the piles for the pier. However, the pier would have a surface area of 3.6 acres, mostly over open water, which would require a lease or easement from the state of Maine.

Land use along the sendout pipeline right-of-way is generally comprised of existing right-of-way, forested land, developed land, agricultural land, and grassland. Construction of the sendout pipeline and associated aboveground facilities would temporarily disturb a total of 254.6 acres, of which 138.2 would be permanently maintained as right-of-way. The construction right-of-way would partially overlap an existing EMEC electric transmission line right-of-way for approximately 9.5 miles, and an existing M&NE pipeline right-of-way for approximately 2.5 miles. Pending negotiations with EMEC, the permanent right-of-way may also partially overlap the existing transmission line right-of-way. The sendout pipeline route would avoid the Moosehorn NWR and the Gardner Wildlife Sanctuary. Pipeline installation would cross a network of ATV trails; however, the use of these trails would not be affected by construction or operation.

Downeast originally identified 19 residences within 50 feet of the permanent right-of-way for the sendout pipeline and filed site-specific plans, which were included in the draft EIS. After issuance of the draft EIS, Downeast filed revised site-specific plans which are included in Appendix P of this final EIS. Downeast incorporated those revisions into its proposed route, and subsequently, only two residences would be approximately 50 feet from the construction right-of-way. In the draft EIS, we specifically requested landowner comments on the residential site-specific plans. We have not received any landowner comments about these plans.

LNG vessels transiting to the LNG terminal would pass by developed areas in Eastport, Maine and St. Andrews, New Brunswick, and scattered seasonal and permanent residences along the route. The LNG marine traffic route would pass in close proximity to Gleason Point Park, Frost Island, an unnamed island in Perry, Carlow Island/Moose Island Scenic Area, Shackford Head State Park, Sumac Island, an unnamed island in Eastport, and Quoddy Head State Park in Lubec. No federal parks occur in the transit route. The shoreland and offshore waters of Mill Cove receive light recreational use for clamming, lobstering, boating, and fishing. Other recreational areas in the vicinity of the terminal include two scenic turnouts along U.S. Route 1.

As part of its WSR, the Coast Guard has recommended the establishment of comprehensive safety and security zones around LNG marine vessels during transit up Head Harbour Passage, Western Passage, and Passamaquoddy Bay for the protection of the LNG vessels, other waterway users, and area residents. Moving combined safety and security zones around the LNG carrier, fixed security zones at the terminal, and one-way traffic could affect other commercial and recreational traffic using the waterway. These could cause temporary impacts on recreational boating and fishing, HMSC research vessels, and the tidal energy construction vessels while the LNG vessel is in transit or moored at the unloading facility. Because the vessel in transit security zone would move with the vessel, the impacts would be of short duration at any given point along the shipping route. In addition, recreational boating and fishing in the area is relatively light. Due to the limited time that nearby marine traffic could be interrupted, impacts on commercial marine activity, including fishing boats, whale watching vessels, and ferries, would be insignificant.

#### 5.1.6.2 Visual

LNG marine vessels within the waterway could be viewed by motorists on U.S. Route 1 and other roads with views to Passamaquoddy Bay, and by tourists, boaters, hikers, and residents with sporadic views of the marine traffic route. Although the vessels would be large and highly visible, they would be viewed for only short durations in areas already used for shipping by tankers and commercial shipping vessels.

Due to the forested rolling hills in the area of the LNG terminal, much of the onshore facility would be screened from areas to the north and south. The 30-foot-high outer vapor fence would be installed along the western site property boundary adjacent U.S. Route 1 and would be a prominent visual feature to vehicles driving along about a one-half mile length of the roadway. The Downeast LNG pier would be primarily visible from Trimble Mountain and along the coast, U.S. Route 1, Mill Cove and portions of Passamaquoddy Bay, the St. Croix River, St. Andrews, New Brunswick, and visitors to the interpretive center for the St. Croix Island International Historic Site in Canada. Portions of the outer vapor fence, storage facilities, and terminal would be viewed by four abutting residences, several residences on the north side of Mill Cove, and residences in the vicinity of the intersection of U.S. Route 1 and Ridge Road. To reduce the potential visual impact of the facility, Downeast has proposed to paint the storage tanks a neutral color and use equipment specifically designed to reduce off-site light spillage. In addition, we are recommending that Downeast develop a plan to reduce potential visual impacts from the outer vapor fence.

No designated visual resource areas would be affected by the pipeline. The impacts associated with construction of the pipeline would be short-term; the construction right-of-way would be restored to pre-existing conditions and the permanent right-of-way would be maintained in an herbaceous state. Approximately 12 miles of the sendout pipeline is adjacent to existing rights-of-way and in an area of sparse development; therefore, the permanent right-of-way would not be visible to many motorists or residents.

#### 5.1.6.3 Coastal Zone Management

The proposed waterway for LNG marine traffic from Friar Roads to Mill Cove lies within the designated coastal zone management area. Both the LNG terminal and a portion of the sendout pipeline within the towns of Robbinston and Calais are within the designated coastal zone management area. Federal actions affecting Maine coastal resources require a consistency review to determine the project’s consistency with state and local environmental laws, regulations, standards, and coastal policies. The Maine SPO coordinates the consistency review as necessary and serves as a single point of contact to receive requests for consistency reviews. Downeast submitted its request for consistency review in December 2006; it was withdrawn by Downeast in November 2007 and Downeast plans to resubmit its request following issuance of the final EIS. As part of the CZMA, the Maine Mandatory Shoreland Zoning Act requires that municipalities protect shoreland areas by adopting shoreland zoning maps and ordinances. The Town of Robbinston Planning Board granted a land use permit for the LNG terminal on February 16, 2006, under its Shoreland Zoning Ordinance and a Conditional Land Use Permit. The City of Calais determined that the sendout pipeline, as a regulated utility facility, would fall under zoning exemptions within its shoreland district. Downeast filed an application for a Permit by Rule under the NRPA and an application under the Site Location of Development Law with the Maine DEP in December 2006, which were withdrawn by Downeast along with other State permit applications on November 11, 2007, and it would resubmit these applications following issuance of the final EIS. To ensure consistency with the CZMA, we are recommending that Downeast file the Maine Department of Agriculture consistency determination prior to construction of the project.

### 5.1.7 Socioeconomics

The proposed project would result in some benefits to the project area, as it would provide small increases in population to an area that has declined in population over past decades, improve employment and training opportunities for local residents, increase personal income, and provide an improved tax base with increases in local revenues. There may be short-term adverse impacts on local public safety and other services during the construction phase, but these impacts would be localized and insignificant. Long-term adverse impacts would be negligible. Environmental justice impacts would be beneficial.

Most impacts would occur in Washington County, although adjacent counties and other areas may furnish a portion of the labor for the project construction, and could also benefit from purchases of equipment and supplies. Impacts would likely be concentrated in the eastern portion of Washington County, in the vicinity of the LNG facilities and pipeline.

Along the Downeast LNG transit route are small towns such as Eastport, Lubec, Perry, and Robbinston, Maine, the Pleasant Point Reservation, and Campobello Island, West Isles, Pennfield, and St. Andrews, New Brunswick, Canada. These towns would not be significantly affected by normal LNG marine vessel operations.

Commercial marine traffic and other economic activity along the waterway could be affected by the passage of the LNG vessels. Impacts on commercial vessels could result from the safety and security zones around the LNG vessel during transit. In certain locations, vessels could experience delays; however, some vessels may be allowed to transit through the LNG vessel security zones with the specific permission of the COTP, determined on a case-by-case basis.

Downeast has developed a comprehensive compensation plan to address any potential loss of fishing equipment or income as a result of unavoidable impacts by Downeast LNG vessels. Downeast consulted with the Cobscook Bay Fishermen's Association, the Fundy North Fishermen's Association, and other sources to update this Fishermen Communication, Coordination, and Compensation Plan to reduce and/or mitigate any adverse impacts on commercial fishing from the project. To ensure that appropriate compensation and mitigation planning measures are developed, we are recommending that Downeast continue to consult with the Maine DMR and appropriate representatives of the local lobster fishery to finalize its Fishermen Communication, Coordination and Compensation Plan and file the plan prior to construction of the Downeast LNG terminal. Downeast has negotiated an agreement with the Mill Cove herring weir owner for compensation in the event of any loss that may result from the operations of the LNG facilities.

The Town of Robbinston and Downeast finalized a "Host Community Benefits Agreement" that specifically outlines a number of commitments by Downeast if the project is developed. These commitments, outlined early in the project development phase, serve to ensure that project benefits are shared with the people of Robbinston and that certain Downeast obligations and services are documented in a legally binding document.

### 5.1.8 Transportation

#### 5.1.8.1 Onshore Traffic

A project-specific traffic capacity analysis in the area of Robbinston, Maine was performed by Downeast to evaluate future roadway levels of service with the addition of construction and facility operation traffic. Traffic impacts associated with construction of the LNG terminal were estimated for both material delivery and worker transportation. Limited traffic delays could occur at pipeline roadway crossing locations. The traffic analysis concluded that the site driveway, U.S. Route 1, and Ridge Road would operate with acceptable levels of service, given the predicted traffic increases from project construction and operation. Downeast has agreed to implement traffic mitigation measures to minimize impacts, including the use of flaggers, daily roadway cleaning, the construction of turning lanes at the facility entrance, roadway striping and signage, and the prohibition of employee parking on U.S. Route 1. Finally, Downeast would consult with the Maine DOT and the local transportation departments of affected communities regarding the need for improvements that might be identified and deemed necessary in the future.

#### 5.1.8.2 Marine Traffic

Downeast has indicated that construction materials would be delivered by land, via U.S. Route 1. Marine traffic associated with construction of the terminal would be minimal and limited to the arrival and departure of construction barges and tugs. With coordination and advance notice regarding the construction barges, impacts on fishing vessels, ferries, and other marine traffic would be minimal.

During operations, Downeast estimates one LNG marine vessel every five to seven days in the winter and one vessel every eight to ten days in the summer, approximately 60 vessels per year. A typical transit, from the time an LNG vessel would enter Head Harbour Passage to the time it would reach the proposed Downeast LNG terminal, would take approximately 2.5 to 3.5 hours; however, the time it would take for an LNG vessel (traveling at an estimated speed of 10 knots) to pass any given point would correspond to about 18 minutes. LNG vessels would follow a circuitous route through both U.S. and Canadian waters, virtually the same route as currently used by all deep-draft vessels servicing Passamaquoddy Bay port areas, including the ports of Bayside, New Brunswick, and Eastport, Maine. These ports receive on average an estimated

125 deep-draft vessel arrivals per year. The Downeast LNG Project would therefore result in a roughly 50 percent increase in anticipated deep-draft vessel traffic. Coordination with the Coast Guard and other waterway and port authorities in the area, and advance notice of the arrival and departure of LNG tankers, along with the implementation of vessel traffic management practices recommended by the Coast Guard's WSR, would reduce impacts on other marine traffic, both commercial and recreational, to an insignificant level.

### 5.1.9 Cultural Resources

In its January 25, 2007 letter to Downeast's cultural resources consultant, the SHPO found that the LNG vessel transit, in and of itself, is not likely to affect aboveground or archaeological resources. We concur.

Downeast conducted a marine archaeological survey of 57 acres offshore adjacent to its proposed LNG terminal, covering the proposed pier and berthing area. This survey found no evidence of submerged cultural resources. However, four historic-era fish weirs were recorded by onshore historic archaeological surveys. Downeast's consultant recommended that these resources should be considered not eligible for the NRHP, requiring no further work. Onshore archaeological and architectural surveys did not identify any other resources within the terminal APE. Downeast believes that the LNG terminal would have no adverse visual impacts on the Saint Croix Island International Historic Site in Bayside, New Brunswick, about 5.2 miles northwest. We and the SHPO agree that no historic properties would be affected within the APE for the proposed LNG terminal.

Downeast documented archaeological surveys of portions of the sendout pipeline route. These surveys recorded one prehistoric site and seven historic sites. All of these sites appear to be outside of the proposed pipeline construction right-of-way and would not be adversely impacted. Downeast also conducted an architectural survey that identified five historic complexes near the pipeline route recommended as eligible for the NRHP. However, the SHPO's June 25, 2007 review of the architectural survey report disagreed with those recommendations, and requested additional information. We defer our opinions until Downeast produces an architectural report acceptable to the SHPO.

In January 2008, Downeast advised the SHPO of the amended pipeline route and requested continued consultation on the project. The SHPO responded on January 31, 2008, requesting additional archaeological and architectural surveys covering the new pipeline route. The results of all cultural resources inventories, including the amended pipeline route and associated facilities, have not yet been filed with the Commission. We will defer making determinations of eligibility and effect until the entire APE for the pipeline is inventoried, and the SHPO has had the opportunity to comment on all reports, including a revised architectural survey report that addresses its previous concerns. Therefore, we are recommending that Downeast not begin construction and use of all proposed facilities until it files the remaining survey and evaluation reports, any required treatment plans, comments of the SHPO and appropriate Indian Tribes, and the Director of OEP notifies Downeast in writing that it may proceed with treatment or construction.

In a February 29, 2008 letter to the Commission, the BIA expressed concern that the project may have an impact on the cultural and religious interests of the Passamaquoddy Tribe. The

Passamaquoddy Tribe has raised a number of issues regarding potential project impacts on cultural sites or aboriginal fishing rights. The Tribe objected to the placement of the pipeline across islands within the St. Croix River. Downeast proposes to use an HDD to cross the St. Croix River and, in response to this comment, has amended the pipeline route to avoid encroaching on any designated Indian trust lands. Downeast has not yet resolved other issues raised by the Tribe. We are recommending that Downeast file documentation of continued consultations with the Passamaquoddy Tribe and other Native Americans interested in the project's potential impacts on cultural resources and seek resolution of identified project-related impacts on archaeological sites, burials, existing historic properties, and sites of religious or cultural importance within the APE.

### 5.1.10 Air Quality and Noise

#### 5.1.10.1 Air Quality

Construction of the marine and land-based portions of the LNG terminal would be performed simultaneously. These construction activities would generate tailpipe emissions (due to fossil fuel combustion from equipment and vehicles) and fugitive emissions (ground and roadway dust). The worst case emissions for any given year of construction are estimated at 21.3 tpy of CO, 46.5 tpy of $NO_x$, and 37.4 tpy of $PM_{10}$. Although residents near the project may see an elevated level of fugitive dust, emissions due to construction activities would not have a significant impact on the regional air quality.

Estimated worst case annual emissions generated by construction of the sendout pipeline include 116.7 tons of NOx, 6.1 tons of VOCs, and 16.0 tons of $PM_{10}$. Anticipated emissions would be temporary and would move along with pipeline construction. Thus the emissions would not result in significant impacts on regional air quality.

Operation of the Downeast LNG terminal would generate air pollutant emissions from stationary combustion equipment, both onshore and offshore, and from LNG tankers and support vessels that travel to and from the facility. Operational emissions from the terminal and vessels are estimated to be 116.9 tpy of $NO_x$, 66.9 tpy of CO, 18.8 tpy of VOC, 6.75 tpy of $SO_2$, 4.37 tpy of $PM_{10}$, and 4.07 tpy of $PM_{2.5}$. Air quality impact modeling indicates that the impact of the Downeast LNG Project primary emissions would not result in a violation of the Class I or Class II NAAQS or the Maine AAQS.

We also evaluated a visibility impact analysis done by Downeast for the Moosehorn Wilderness Area – Baring Unit, Moosehorn Wildernes Area-Edmunds Unit, Roosevelt-Campobello International Park Class I areas as well as St. Croix Island. We determined that the impact would be below visibility impact limits at all locations with the exception of the Moosehorn Wilderness Area – Baring Unit. Although slightly above the visibility limits, we determined that the actual operational impact would be less due to the fact that the model is highly conservative and only three SCVs would run at any given time instead of the four that were modeled.

Similarly, the sulfur and nitrogen deposition analysis done for the Class I areas and St. Croix Island identified that the Downeast LNG terminal would contribute to nitrogen and sulfur deposition levels in excess of the Class I limits. Thus the Downeast LNG terminal may contribute to a significant adverse affect on the Class I areas and St Croix Island.

Because Downeast LNG has not refiled its PSD, or Title V permit with the state of Maine, we are including a recommendation that Downeast file the required state permits along with a demonstration that the impacts would not be greater than impacts identified in this EIS.

There would be no emisisons from the pipeline except figutive methane emissions which would not be significant.

In summary, the Downeast LNG terminal impact on air quality during operation would not be significant with the exception of potential significant deposition impacts to the Class I areas and St. Croix Island.

### 5.1.10.2 Noise

Noise would affect the local environment during both the construction and operation of the proposed Downeast LNG terminal. At any location, both the magnitude and frequency of noise associated with the project may vary considerably over the course of the day or throughout the week. Noise would be associated with a variety of different project-related activities including LNG marine traffic, construction, and operation of marine-based and land-based facilities, and construction of the sendout pipeline. Potential underwater noise impacts were also assessed for project construction and operation.

Noise generated by LNG vessel traffic along the waterway from the territorial sea to the proposed LNG terminal would be similar to noise from other large ships currently using the waterway. Downeast prepared a noise assessment for four of the closest points of land along the route. The highest day-night sound level ($L_{dn}$) of 51 dBA was predicted for a nighttime transit past the east shore of Moose Island. Noise associated with the normal operation of the additional LNG vessels along the waterway would not cause a significant increase in noise impacts.

Noise produced during construction of the Downeast LNG terminal and associated pipeline could create short-term annoyances to some residences, and could have short-term impacts on some aquatic species, nesting birds, and other wildlife in the area. While the noise from standard onshore pile driving could result in high levels, or noise for an extended period of time that would be significant, Downeast has commited to using a vibratory pile driver. This would reduce noise impacts below the level of interference with human speech intelligibility.

The sound generated by construction vessels is proportionate to ship size, speed, engine load and rpm with broadband source levels driven primarily by propeller cavitations, hydrodynamic flow over the hull and hull appendages, and operation of machinery onboard. Aside from tug operations, the primary sources of underwater noise during construction of the LNG terminal would be the installation of the steel pilings. Construction of the sendout pipeline is primarily land-based but would also rely on special techniques for crossing waterbodies, roads, railroads, and utilities such as the HDD method. Activities during the construction phase have the potential to cause noise impacts on the surrounding area. Noise associated with most construction equipment would be intermittent, and all major construction activity would be limited to daytime or daylight hours. Estimates provided by Downeast show that sound levels at NSAs near some of the HDD sites would exceed 55 dBA. Where 24-hour drilling is necessary and $L_{dn}$ sound levels at NSAs are expected to exceed 55 dBA, Downeast would reduce noise levels at the NSAs by implementing noise control measures. These mitigation measures would reduce sound levels from HDD operations up to levels ranging from 10 to 15 dBA. To ensure that this mitigation is sufficient, we are recommending that prior to construction, Downeast file an HDD noise mitigation plan for our review and approval, monitor noise levels during drilling, and make all reasonable efforts to restrict noise to no more than an $L_{dn}$ of 55 dBA at the NSAs.

Noise from operation of the LNG terminal facility has been estimated to be below the FERC limit of 55 dBA $L_{dn}$ and should not create a significant noise impact at NSAs near the project site. To determine actual noise from operation of the terminal, we are recommending that Downeast file a noise survey no later than 60 days after placing the terminal in service and install additional noise controls if necessary. At typical cruising speeds, source sound levels emitted by LNG vessels are dominated by propeller cavitation. Underwater noise associated with the pilot vessel would be expected to be negligible in comparison to that generated from the LNG marine vessel and assist tugs. The use of LNG vessel thrusters would be minimized when docking to the pier, due to the reliance on tugboats that would actively assist during docking. The buried sendout pipeline would not contribute to aboveground noise levels. Operational noise associated with the sendout pipeline would be limited to the immediate vicinity of the three mainline block valves, located at each end of the pipeline and at MP 17.2. Some minor noise may be heard immediately around the metering station.

To ensure that the noise impacts at NSAs near the meter station, located within the LNG terminal site, do not exceed 55 dBA $L_{dn}$, we are recommending that Downeast file a noise survey no later than 60 days after placing the LNG terminal and meter station in service. If the noise attributable to the operation of the LNG terminal and meter station at maximum flow exceeds an $L_{dn}$ of 55 dBA at any nearby NSA, Downeast should install additional noise controls to meet that level within one year of the in-service date.

### 5.1.11 Reliability and Safety

We evaluated the safety of both the proposed LNG import terminal facility and the related LNG vessel transit through the Passamaquoddy Bay Waterway. As part of our evaluation, we performed a technical review of the preliminary engineering designs and conclude that sufficient layers of safeguards would be included in the facility designs to mitigate the potential for an incident that could impact the safety of the off-site public. DOT reviewed the data and methodology Downeast used to determine the design spills based on the flow from various leakage sources, including piping, containers, and equipment containing hazardous liquids. In a letter to FERC dated January 30, 2014, DOT stated it has no objection to Dowenast's methodology for determining the candidate design spills used to establish the required siting for its proposed LNG import facility. Based on the hazard area calculations performed by Downeast, we conclude that potential hazards from the siting of the facility at this location would not have a significant impact on public safety

On January 6, 2009, the Coast Guard issued an LOR and made an assessment in its WSR (Appendix B) that the Passamaquoddy Bay Waterway is suitable for the type and frequency of marine traffic associated with the proposed Downeast LNG Project, provided that all of the risk mitigation measures outlined in section 4.6 of the WSR are implemented by the applicant to the satisfaction of the COTP. The risk mitigation measures in the WSR also provide that Downeast must determine and comply with all applicable Canadian laws and regulations applicable to the safe and secure navigation and the regulation of maritime traffic, that comply with customary international law. The Coast Guard has the authority to prohibit LNG transfer or LNG vessel movements within U.S. waters if such action is necessary to protect the waterway, port or marine environment. If this project is approved and if appropriate resources are not in place prior to LNG vessel movement along the waterway, then the Coast Guard would consider at that time what, if any, vessel traffic and/or facility control measures would be appropriate to adequately address navigational safety and maritime security considerations. As a result, we are recommending that Downeast should receive written authorization from the Director of OEP before commencement of service at the LNG terminal. Such authorization would only be granted following a determination by the Coast Guard that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by Downeast or other appropriate parties.

We are recommending that Downeast develop an Emergency Response Plan in consultation with the Coast Guard and state and local agencies. Necessary security measures would further be incorporated into a Transit Management Plan that would clearly spell out roles, responsibilities, and specific procedures for LNG marine traffic transiting to the terminal, as well as for all agencies involved in implementing security and safety during operations. We are also recommending that Downeast develop a Cost-Sharing Plan that identifies the mechanisms for funding all project-specific security/emergency management costs that would be imposed on state and local agencies.

The transportation of natural gas by pipeline involves some incremental risk to the public in the event of an accident and subsequent release of gas. The greatest hazard is a fire or explosion following a major pipeline rupture. The DOT is mandated to provide pipeline safety under Title 49, U.S.C. Chapter 601. The natural gas pipeline and associated aboveground facilities proposed for the Downeast LNG Project must be designed, constructed, operated, and maintained in accordance with the DOT Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. The sendout pipeline would be continuously monitored from a SCADA system at an operations control center. Downeast would prepare an Operations and Maintenance Procedures manual for the pipeline system that meets the requirements of section 192.605. The pipeline would be patrolled and inspected on the ground on a periodic basis per DOT requirements. Under section 192.615, Downeast would establish an emergency plan that includes procedures to minimize the hazards in a natural gas pipeline emergency.

The available data show that natural gas transmission pipelines continue to be a safe, reliable means of energy transportation. From 1993 to 2012, there were an average of 61 significant incidents, 6 injuries and 2 fatalities per year. The number of significant incidents over the more than 300,000 miles of natural gas transmission lines indicates that the risk is low for an incident at any given location. The operation of the project would represent a slight increase in risk to the nearby public.

### 5.1.12 Cumulative Impacts

We considered a wide variety of projects and activities in the general area that, in concert with the proposed Downeast LNG Project, could result in cumulative impacts. We evaluated one other LNG project, one offshore gas project, two natural gas pipelines, four tidal energy projects, one road construction project, one border crossing facility, one aquaculture facility, one airport, one wind power project, and the Port of Eastport warehouse project.

Construction of the Downeast LNG Project and some or all of the other project proposals in the area could cause construction related impacts, especially if they are constructed at the same time. Marine water quality could be affected from turbidity and potential spills. Marine fisheries and aquatic resources would be affected from disturbance of bottom habitats, increased turbidity, and noise. These impacts would be localized, short-term, and most likely not occur at the same time. Because the construction time periods and physical impact areas for these projects are not expected to overlap, cumulative impacts on marine fisheries and aquatic organisms during construction of the projects would be insignificant. During operation, the Downeast LNG Project, together with the other projects in the area, would contribute to increased ship traffic along the ship channel, and cumulative impacts on marine water quality from water withdrawals and discharges, installation of structures (ocean current generation modules), and impacts on marine fisheries and mammals. Downeast has attempted to minimize the area of permanent impact on marine habitat through terminal siting, design, and operational controls. It is expected that other projects would follow a similar approach to avoid, minimize, and mitigate for permanent impact on marine habitats during their respective regulatory review and approval processes.

The permanent conversion of forest land communities to an herbaceous community along the Downeast sendout pipeline in combination with other past, present, or reasonably foreseeable future projects, could fragment some wildlife habitats and degrade important wetland habitats. In most instances, cumulative effects of temporary wetlands impacts would be minimal because of the limited temporal and spatial overlap between the projects. Although the Downeast LNG Project and other projects would result in the degradation of some wildlife habitats, compensatory mitigation programs for each of these projects would likely be designed to provide a net benefit to the ecosystem.

The Downeast LNG Project, together with the other projects in the area, would cumulatively benefit the local economy through job creation and wages, increased income in the region, purchases of goods and materials, and increased tax revenues. A further effect would be a small increase in the area's population, which is considered a benefit given declining populations in recent decades. We recognize that the project could spur entrepreneurial innovation; however, we do not believe that the Downeast LNG Project would set a precedent for energy generation or industrialization in the area. Any new developments in the project area would require regulatory review to determine impacts, mitigation, and compensation.

Most impacts associated with the proposed Downeast LNG Project would be relatively minor, and we have included recommendations in this EIS to further reduce the associated environmental impacts. Consequently, only a small cumulative effect is anticipated when the impacts of the proposed project are added to past, present, or reasonably foreseeable future projects in the area.

### 5.1.13 Alternatives

Alternative analyses were completed as part of FERC's environmental review. Under the no action alternative, Downeast would not be able to provide additional natural gas supplies in order to help meet the increasing natural gas demand in New England. We conclude that neither conservation measures nor renewable energy sources are expected to replace or significantly offset the demand for additional natural gas supplies in New England by the projected in-service date of the Downeast LNG Project.

We evaluated system alternatives that would make use of other existing or previously but no longer proposed LNG import terminals or natural gas pipeline systems. Expansion of existing or previously proposed but cancelled onshore LNG facilities would require construction of new LNG storage and vaporization facilities, additional LNG vessel traffic, and new natural gas pipelines. Each of these alternatives would have an equal or greater environmental impact than the proposed Downeast LNG Project. The Cacouna and Rabaska Projects would not supply the U.S. northeast markets. The Deep Panuke Project would partially meet the objectives of the Downeast LNG Project, but would also have its own set of environmental impacts, primarily from the development of offshore production facilities, onshore receiving facilities, and associated pipelines. It is possible that some combination of two or more of the existing or previously proposed but cancelled LNG terminal projects, or future expansions of those projects, could serve as an alternative to the proposed Downeast LNG Project; however, such an alternative is speculative. Northeast Gateway and Neptune would have less environmental impact than the Downeast LNG Project; however, neither would provide LNG storage capacity. Furthermore, we recognize that market demand could justify construction of the Downeast LNG Project in addition to the existing Northeast Gateway Project and Neptune LNG Project.

Existing natural gas pipeline systems in New England may not have the capacity to transport the additional volumes of natural gas proposed in this project. While an expansion of one or more of these systems could potentially provide the capacity for natural gas volumes proposed by Downeast, such expansions would not provide a source of imported natural gas and additional natural gas storage facilities. In addition, an expansion of one or more of these other pipeline systems would include their own set of environmental impacts.

We evaluated alternative terminal sites, pier designs, and LNG vaporization technologies, none of which would provide significant environmental advantages over the proposed site. We also analyzed pipeline route alternatives and variations that may avoid or minimize environmental impact on specific sensitive areas or areas of concern. The proposed pipeline route no longer crosses the Moosehorn NWR and impacts on the Baileyville WPA would be minimized primarily through use of spill control practices. We have determined that the proposed sendout pipeline route, as modified throughout our review, is environmentally preferable to the identified alternatives.

We evaluated alternative LNG vessel designs that could reduce water usage. Vessels for the Northeast Gateway and Neptune offshore LNG projects include on-board regasification systems that are capable of a unique heat exchange and water use reduction. Because the proposed Downeast LNG terminal is designed for accepting and storing LNG in its liquid phase, the LNG vessels calling on the terminal would be standard LNG vessels designed for transport and offloading of LNG in liquid phase. These vessels would not include on-board regasification systems, and would not be capable of the unique heat exchange that is available for the on-board regasification ships. Therefore, the opportunities to accomplish similar water use reductions through LNG vessel design would not be available to the Downeast LNG Project.

Overall, the proposed project would result in fewer environmental impacts than any alternatives considered. This includes consideration of the project's objectives, and the environmental impacts associated with the location, and construction methods of the alternatives. In addition, we have included recommendations in this EIS that would modify the Downeast proposal to further reduce and avoid impacts. In summary, we have determined that Downeast's proposed project, as modified by our recommended mitigation measures, is the preferred alternative that can meet the project objectives.

## 5.2 FERC STAFF'S RECOMMENDED MITIGATION

If the Commission authorizes the proposed Downeast LNG Project, we recommend that the following measures be included as specific conditions in the Commission's Order. We believe these measures would further mitigate environmental impacts associated with construction and operation of the proposed project.

1. Downeast shall follow the construction procedures and mitigation measures described in its applications, supplemental filings (including responses to staff data requests), and as identified in the EIS unless modified by the Commission's Order. Downeast must:
   a. request any modification to these procedures, measures, or conditions in a filing with the Secretary;
   b. justify each modification relative to site-specific conditions;
   c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and
   d. receive approval in writing from the Director of OEP **before using that modification**.

2. For LNG facilities, the Director of OEP has delegated authority to take all steps necessary to ensure the protection of life, health, property, and the environment during construction and operation of the project. This authority shall include:
   a. stop-work authority and authority to cease operation; and
   b. design and implementation of any additional measures deemed necessary to assure continued compliance with the intent of the conditions of the Order.

3. For pipeline facilities, the Director of OEP has delegation authority to take whatever steps are necessary to ensure the protection of all environmental resources during construction and operation of the project. This authority shall allow:
   a. modification of conditions of the Order; and
   b. design and implementation of any additional measures deemed necessary (including stop-work authority) to ensure continued compliance with the intent of the environmental conditions as well as the avoidance or mitigation of adverse environmental impact resulting from project construction and operation.

4. **Prior to any construction**, Downeast shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, EIs, and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs before becoming involved with construction and restoration activities.

5. The authorized facility locations shall be as shown in the EIS, as supplemented by filed alignment sheets. **As soon as they are available, and before the start of construction**, Downeast shall file with the Secretary revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

   Downeast's exercise of eminent domain authority granted under NGA section 7(h) in any condemnation proceedings related to the Order must be consistent with these authorized facilities and locations. Downeast's right of eminent domain granted under NGA section 7(h) does not authorize it to increase the size of its natural gas pipeline to accommodate future needs or to acquire a right-of-way for a pipeline to transport a commodity other than natural gas.

6. Downeast shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations and staging areas, pipe storage and ware yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, and documentation of landowner approval, whether any cultural resources or federally-listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **before construction in or near that area**.

   This requirement does not apply to extra workspaces allowed by FERC's Plan or minor field realignments per landowner needs and requirements that do not affect other landowners or sensitive environmental areas such as wetlands.

   Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

   a. implementation of cultural resources mitigation measures;
   b. implementation of endangered, threatened, or special concern species mitigation measures;
   c. recommendations by state regulatory authorities; and
   d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

7. **At least 60 days before construction begins**, Downeast shall file with the Secretary an Implementation Plan for review and written approval by the Director of OEP. Downeast must file revisions to the plan as schedules change. The plan shall identify:

   a. how Downeast will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EIS, and required by the Order;
   b. how Downeast will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and

construction drawings so that the mitigation required at each site is clear to onsite construction and inspection personnel;

c. the number of EIs assigned, and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;
d. company personnel, including EIs and contractors, who will receive copies of the appropriate material;
e. the location and dates of the environmental compliance training and instructions Downeast will give to all personnel involved with construction and restoration (initial and refresher training as the project progresses and personnel change), with the opportunity for OEP staff to participate in the training session(s);
f. the company personnel (if known) and specific portion of Downeast's organization having responsibility for compliance;
g. the procedures (including use of contract penalties) Downeast will follow if noncompliance occurs; and
h. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram), and dates for:
   (1) the completion of all required surveys and reports;
   (2) the environmental compliance training of onsite personnel;
   (3) the start of construction; and
   (4) the start and completion of restoration.

8. Downeast shall employ one or more EIs for the terminal site and each construction spread for the pipeline. The EIs shall be:

   a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or other authorizing documents;
   b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract (see condition 7 above) and any other authorizing document;
   c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;
   d. a full-time position, separate from all other activity inspectors;
   e. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and
   f. responsible for maintaining status reports.

9. Beginning with the filing of its Implementation Plan, Downeast shall file updated status reports with the Secretary on a **monthly** basis for the terminal and a **weekly** basis for the pipeline until all construction and restoration activities are complete. On request, these status reports shall also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

   a. an update on Downeast's efforts to obtain the necessary federal authorizations;
   b. the construction status at the terminal site and of each spread of the pipeline, work planned for the following reporting period, and any schedule changes for stream crossings or work in environmentally sensitive areas;

c. a listing of all problems encountered and each instance of noncompliance observed by the EI(s) during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);
d. a description of corrective actions implemented in response to all instances of noncompliance, and their cost;
e. the effectiveness of all corrective actions implemented;
f. a description of any landowner/resident complaints that may relate to compliance with the requirements of the Order, and the measures taken to satisfy their concerns; and
g. copies of any correspondence received by Downeast from other federal, state, or local permitting agencies concerning instances of noncompliance, and Downeast's response.

10. **Prior to receiving written authorization from the Director of OEP to commence construction of any project facilities**, Downeast shall file documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

11. Downeast must receive written authorization from the Director of OEP **prior to introducing hazardous fluids into the terminal facilities**. Instrumentation and controls, hazard detection, hazard control, and security components/systems necessary for the safe introduction of such fluids shall be installed and functional.

12. Downeast must receive written authorization from the Director of OEP **before placing the terminal facilities into service**. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with FERC approval and applicable standards, can be expected to operate safely as designed, and the rehabilitation and restoration of the areas affected by the terminal are proceeding satisfactorily.

13. Downeast must receive written authorization from the Director of OEP **before placing the pipeline into service**. Such authorization will only be granted following a determination that rehabilitation and restoration of the right-of-way and other areas affected by the pipeline are proceeding satisfactorily.

14. **Within 30 days of placing the authorized facilities in service**, Downeast shall file an affirmative statement, certified by a senior company official:

    a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or
    b. identifying which of the authorization or certificate conditions Downeast has complied with or will comply with. This statement shall also identify any areas affected by the project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

15. Downeast shall **not begin construction** of the pipeline from MP 17.7 to MP 27.2 **until** Downeast files with the Secretary, for review and written approval by the Director of OEP, updated alignment sheets, developed in coordination with EMEC, depicting the pipeline adjacent to the existing transmission line. *EIS Section 2.2.2.1*

16. Downeast shall file the following information, stamped and sealed by the professional engineer-of-record, with the Secretary for review and written approval by the Director of OEP:
    a) structure and foundation design drawings and calculations of the LNG tanks and other LNG import terminal facilities;
    b) seismic specifications used in conjunction with the procuring equipment; and
    c) quality control procedures that will be used for design and construction. *EIS Section 4.1.4.1.1*

    In addition, Downeast shall file, in its Implementation Plan, the schedule for producing this information.

17. **Prior to construction of the pipeline facilities**, Downeast shall file with the Secretary the location by milepost of all private wells and springs within 150 feet of construction activities. Downeast shall conduct, with the well owner's permission, pre- and post-construction monitoring of well yield and water quality for these wells. In the event a water well or system is damaged as a result of construction, Downeast shall arrange for a temporary source of potable water, if required, and provide for the repair of the well or replacement of the water supply. *EIS Section 4.3.1.3*

18. **Within 30 days of placing the pipeline facilities in service**, Downeast shall file a report with the Secretary discussing whether any complaints were received concerning well yield or water quality of the private wells and springs within 150 feet of construction activities and how each complaint was resolved. *EIS Section 4.3.1.3*

19. **Prior to the construction of the LNG terminal facilities,** Downeast shall develop a Marine SPCC Plan to include procedures that would be implemented should spills of oil, gas, lubricants, or other hazardous materials occur during construction and operation of the marine terminal. In addition to addressing emergency spill response and cleanup procedures, this plan shall include a description of general spill prevention measures such as material handling practices, personnel training, and inspection. Downeast shall file the Marine SPCC Plan with the Secretary for review and written approval by the Director of OEP. *EIS Section 4.3.2.1*

20. **Prior to construction of the LNG terminal facilities**, Downeast shall file with the Secretary a final plan for the discharge of the excess SCV water, for the review and written approval of the Director of OEP. The discharge plan shall include discharge location, rate and frequency of discharge, copies of applicable permit applications, and all measures to be used to mitigate environmental impacts at the discharge location. *EIS Section 4.3.2.1*

21. **Prior to construction of the pipeline facilities,** Downeast shall consult with NOAA Fisheries on the proposed St. Croix HDD plan and file with the Secretary copies of NOAA Fisheries comments on the St. Croix HDD plan. *EIS Section 4.3.2.2*

22. Downeast shall continue consultation with the COE, EPA, and the Maine DIFW and DEP to finalize its wetland mitigation and compensation plan. Downeast shall file the final plan with the Secretary, along with agency comments and applicable approvals, **prior to construction of the pipeline or LNG terminal facilities**. *EIS Section 4.4.1.2*

23. **Prior to construction of the LNG terminal facilities**, Downeast shall conduct project-specific eelgrass mapping within Mill Cove to determine the presence and extent of eelgrass within areas that could be affected by the Project within Mill Cove. Results of the eelgrass mapping shall be incorporated into compensatory mitigation planning, as needed. Downeast shall file the results of the eelgrass mapping, and any resulting mitigation plan for potential impacts on eelgrass, including records of consultation with Maine DMR and NOAA Fisheries regarding mitigation, with the Secretary for review and written approval by the Director of OEP. *EIS Section 4.4.2.2*
24. Downeast shall continue to consult with the FWS to determine if there are FWS-recommended seasonal or construction timing restrictions that Downeast could incorporate into its construction plan to minimize impacts of the sendout pipeline along the Moosehorn NWR boundaries. **Prior to construction of the pipeline facilities**, Downeast shall file with the Secretary copies of its correspondence with FWS and a description of the construction timing restrictions and/or mitigation measures it has agreed to implement along the Moosehorn NWR boundaries. *EIS Section 4.5.1.3*
25. Downeast shall continue to consult with the Maine DEP, DIFW, and BEP to finalize its DWA mitigation package. **Prior to construction of the pipeline facilities**, Downeast shall file with the Secretary the final DWA mitigation package and copies of the consulted agencies' comments on the final package and applicable approvals. *EIS Section 4.5.1.3*
26. Downeast shall continue to consult with NOAA Fisheries, Maine DMR, other appropriate agencies, and appropriate representatives of the local lobster fishery to determine impacts on the local lobster population and any recommended mitigations to minimize impacts on lobster and lobster habitat during all proposed construction and operational activities at the LNG terminal. **Prior to the start of construction of the LNG terminal facilities**, Downeast shall file with the Secretary, for review and written approval by the Director of OEP, its final Fishermen Communication, Coordination and Compensation Plan, including copies of its correspondence with consulted agencies and a description of any mitigation measures it has agreed to implement. *EIS Section 4.5.2.2*
27. Downeast shall continue to consult with NOAA Fisheries, Maine DMR, and other appropriate agencies to determine any recommended seasonal or construction timing restrictions to minimize impacts on marine species and habitats during all proposed in-water work and pile driving activities at the LNG terminal. **Prior to construction of the LNG terminal facilities**, Downeast shall file with the Secretary copies of its final Prevention and Mitigation Manual, to include correspondence with consulted agencies and a description of any mitigation measures it has agreed to implement, including seasonal or construction timing restrictions. *EIS Section 4.5.2.2*
28. Downeast shall **not begin construction until**:
    a. the FERC staff completes Endangered Species Act consultation with the FWS/NOAA Fisheries; and
    b. Downeast has received written notification from the Director of OEP that construction or use of mitigation may begin. *EIS Section 4.6*

29. **Prior to construction of the LNG terminal facilities,** Downeast shall file with the Secretary for review and written approval by the Director of OEP a mitigation plan to reduce the visual impact of the proposed outer vapor fence. *EIS Section 4.7.4.2*

30. **Prior to construction**, Downeast shall file with the Secretary documentation of concurrence from the Maine Department of Agriculture that the project is consistent with the Maine CZMP. *EIS Section 4.7.5.1*

31. **Prior to construction**, Downeast shall file with the Secretary documentation of continued consultations with the Passamaquoddy Tribe, BIA, and other appropriate Indian tribes and Native Americans interested in the project's potential impacts on cultural resources, including access to sites in Mill Cove, and seek resolution of identified project-related impacts on archaeological sites, burials, existing historic properties, and sites of religious or cultural importance within the APE. *EIS Section 4.10.4*

32. Downeast shall not begin construction of facilities and/or use of all staging, storage, or temporary work areas and new or to-be-improved access roads **until**:

    a. Downeast files with the Secretary:
       (1) remaining cultural resources survey report(s);
       (2) site evaluation report(s) and avoidance or treatment plan(s), as required; and
       (3) comments on the cultural resources reports and plans from the Maine SHPO, and interested Native Americans and Indian tribes.

    b. the ACHP is afforded an opportunity to comment if historic properties would be adversely affected; and

    c. the FERC staff reviews and the Director of OEP approves the cultural resources reports and plans, and notifies Downeast in writing that treatment measures (including archaeological data recovery) may be implemented and/or construction may proceed.

    All materials filed with the Commission containing **location, character, and ownership information** about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "**CONTAINS PRIVILEGED INFORMATION – DO NOT RELEASE**." *EIS Section 4.10.4*

33. **Prior to construction of the LNG terminal facilities**, Downeast shall file with the Secretary a copy of its final air permit from the Maine DEP. The permitted emissions shall be consistent with the emissions of criteria pollutants, GHGs, and HAPs analyzed in the final EIS. *EIS Section 4.11.1.3*

34. Downeast shall file a full load noise survey with the Secretary **no later than 60 days after placing the Downeast LNG terminal and meter station into service**. If a full load condition noise survey is not possible, Downeast shall file an interim survey at the maximum possible load **within 60 days of placing the Downeast LNG terminal and meter station into service** and file the full load survey results with the Secretary **within 6 months of the in-service date**. If the noise attributable to the operation of all the equipment of the Downeast LNG terminal and meter station at full operation exceeds 55 dBA $L_{dn}$ at any nearby NSAs, Downeast shall install additional noise controls to meet the level **within 1 year of the in-service date**. Downeast shall confirm compliance with

this requirement by filing a second full load noise survey with the Secretary **no later than 60 days after it installs the additional noise controls**. *EIS Section 4.11.2.3.3*

35. **Prior to construction of the pipeline facilities**, Downeast shall file with the Secretary, for the review and written approval by the Director of OEP, an HDD noise mitigation plan for HDDs R-09-15, C-34-224, C-32-135, C-29-147, C-24-03, BP-06-03, and BP-14-15. The plan shall identify mitigation measures designed to reduce the noise impacts on the NSAs from HDD activities. **During drilling operations**, Downeast shall implement the approved plan, monitor noise levels, and make all reasonable efforts to restrict the noise attributable to the drilling operations to no more than an $L_{dn}$ of 55 dBA at the NSAs. *EIS Section 4.11.2.4.1*

36. Downeast shall file **in its weekly pipeline construction status reports** the following for HDD operations that last more than 10 days:
    a. the HDD entry point noise measurements from the nearest NSA, obtained at the start of drilling operations;
    b. the noise mitigation that Downeast implemented prior to the start of drilling operations; and
    c. any additional mitigation measures that Downeast would implement if the initial noise measurements exceeded an $L_{dn}$ of 55 dBA at the nearest NSA. *EIS Section 4.11.2.4.1*

**Recommendations 37 through 112 shall be applied to the Downeast LNG terminal. Information pertaining to these specific recommendations shall be filed with the Secretary for review and written approval by the Director of OEP either: <u>prior to initial site preparation; prior to construction of final design; prior to commissioning; prior to introduction of hazardous fluids; or prior to commencement of service</u>, as indicated by each specific condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 683 (Docket No. RM06-24-000), including security information, shall be submitted as critical energy infrastructure information (CEII) pursuant to 18 CFR 388.112. See CEII Order No. 683, 71 Fed. Reg. 58,273 (October 3, 2006), FERC Stats. & Regs. ¶31,228 (2006). Information pertaining to items such as: offsite emergency response; procedures for public notification and evacuation; and construction and operating reporting requirements will be subject to public disclosure. All information shall be filed a minimum of 30 days before approval to proceed is requested.**

37. **Prior to initial site preparation**, Downeast shall file the quality assurance and quality control procedures for construction activities. *EIS Section 4.12.3*

38. **Prior to initial site preparation**, Downeast shall include a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems. *EIS Section 4.12.3*

39. **Prior to initial site preparation**, Downeast shall file an overall project schedule. *EIS Section 4.12.3*

40. **Prior to initial site preparation**, Downeast shall provide procedures for controlling access during construction. *EIS Section 4.12.3*

41. **Prior to initial site preparation**, Downeast shall file a complete specification of the proposed LNG tank design and installation. *EIS Section 4.12.3*

42. **Prior to initial site preparation**, Downeast shall file drawings of the storage tank piping support structure and support of horizontal piping at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances. *EIS Section 4.12.3*

43. **Prior to initial site preparation**, Downeast shall file complete plan drawings of the security fencing and of facility access and egress, including the details of the fence and control access and egress from the pipe trestle and dock. *EIS Section 4.12.3*

44. **Prior to initial site preparation**, Downeast shall file certification that all trees would be removed from the area between the vapor fences and the shoreline. Alternatively, Downeast may demonstrate that the spacing of the trees, and any vegetation management plan, would prevent congested areas that could produce offsite overpressures above 1 psi. *EIS Section 4.12.5*

45. Downeast shall develop an Emergency Response Plan (including evacuation) and coordinate procedures with the Coast Guard; state/provincial, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal/tribal agencies. This plan shall include at a minimum:

    a. designated contacts with tribal, state and local emergency response agencies;
    b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;
    c. procedures for notifying residents and recreational users within areas of potential hazard;
    d. evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;
    e. locations of permanent sirens and other warning devices; and
    f. an "emergency coordinator" on each LNG vessel to activate sirens and other warning devices.

    The Emergency Response Plan shall be filed with the Secretary for review and written approval by the Director of OEP **prior to initial site preparation**. Downeast shall notify the FERC staff of all planning meetings in advance and shall report progress on the development of its Emergency Response Plan at **3-month intervals.** *EIS Section 4.12.8*

46. The Emergency Response Plan shall include a Cost-Sharing Plan identifying the mechanisms for funding all project-specific security/emergency management costs that would be imposed on tribal, state and local agencies. In addition to the funding of direct transit-related security/emergency management costs, this comprehensive plan shall include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. The Cost-Sharing Plan shall be filed with the Secretary for review and written approval by the Director of OEP **prior to initial site preparation**. *EIS Section 4.12.8*

47. The **final design** shall provide information/revisions related to those responses in Downeast's April 10, 2007 filing that state that corrections or modifications would be

made to the design. The final design shall specifically address response numbers 2, 8, 10, 13, 15, 23, 24, 25, 26, 27, 30, 31, 33, 34, 38, 51, 54, 56, 59, 61, and 70 using management of change procedures. *EIS Section 4.12.3*

48. The **final design** shall include certification that the facility has been modified to be consistent with the wind speed requirements of 49 CFR § 193.2067 or that DOT has approved the use of a lower wind speed as allowed by § 193.2067(b). Downeast shall consult with DOT on any actions necessary to demonstrate compliance with Part 193. *EIS Section 4.12.3*

49. The **final design** shall provide change logs that list and explain any changes made from the Front-End Engineering Design provided in Downeast's application and filings. A list of all changes with an explanation for the design alteration shall be provided and all changes shall be clearly indicated on all diagrams and drawings. *EIS Section 4.12.3*

50. The **final design** shall provide an equipment list, process and mechanical data sheets, and specifications. *EIS Section 4.12.3*

51. The **final design** shall include spill containment system drawings with dimensions and slopes of curbing, trenches, and impoundments. *EIS Section 4.12.3*

52. The **final design** shall include electrical area classification drawings. *EIS Section 4.12.3*

53. The **final design** shall include the sizing basis and capacity for the final design of pressure and vacuum relief valves for major process equipment, vessels, storage tanks, and vent stacks. *EIS Section 4.12.3*

54. The **final design** shall provide the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3, as required by 49 CFR 193. *EIS Section 4.12.3*

55. The **final design** shall include up-to-date Process Flow Diagrams (PFDs) and Piping and Instrumentation Diagrams (P&IDs). The PFDs shall include heat and material balances. The P&IDs shall include the following information:

    a. equipment tag number, name, size, duty, capacity, and design conditions;
    b. equipment insulation type and thickness;
    c. storage tank pipe penetration size or nozzle schedule;
    d. piping with line number, piping class specification, size, and insulation type and thickness;
    e. piping specification breaks and insulation limits;
    f. all control and manual valves numbered;
    g. valve high pressure side and internal and external vent locations;
    h. relief valves with set points; and
    i. drawing revision number and date. *EIS Section 4.12.3*

56. The **final design** shall include an updated fire protection evaluation carried out in accordance with the requirements of NFPA 59A 2001, chapter 9.1.2 as required by 49 CFR 193. A copy of the evaluation, a list of recommendations and supporting

justifications, and actions taken on the recommendations shall be filed. The fire protection evaluation shall address measures on the prevention of caustic water from entering the firewater tank. *EIS Section 4.12.3*

57. The **final design** shall include complete drawings and a list of the hazard detection equipment. Drawings shall clearly show the location and elevation of all detection equipment. The list shall include the instrument tag number, type and location, alarm indication locations, set points, and shutdown functions of the proposed hazard detection equipment. *EIS Section 4.12.3*

58. The **final design** shall provide a technical review of its proposed facility design that:

    a. identifies all combustion/ventilation air intake equipment and the distances to any possible hydrocarbon release (LNG, flammable refrigerants, flammable liquids and flammable gases); and

    b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shut down any combustion equipment whose continued operation could add to or sustain an emergency. *EIS Section 4.12.3*

59. The **final design** shall provide drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Drawings shall clearly show the location by tag number of all fixed, wheeled, and hand-held extinguishers. The list shall include the equipment tag number, type, capacity, equipment covered, discharge flow rate, and automatic and manual remote signals initiating discharge of the units. *EIS Section 4.12.3*

60. The **final design** shall provide facility plans and drawings showing the location of the firewater and any foam systems. Drawings shall clearly show: firewater and foam piping; post indicator valves; and the location, and area covered by, each monitor, hydrant, water curtain, deluge system, foam system, sprinkler system, and water mist system. The drawings shall also include piping and instrumentation diagrams of the firewater and foam systems. *EIS Section 4.12.3*

61. The **final design** shall specify that the design pressure of sendout equipment containing LNG in low pressure service shall be not less than the design pressure of the piping system. *EIS Section 4.12.3*

62. The **final design** shall specify that LNG relief valves and LNG drains shall not discharge into the vapor system. *EIS Section 4.12.3*

63. The **final design** shall specify that LNG from relief valves and drains is to be returned to storage. *EIS Section 4.12.3*

64. The **final design** shall include provision for vehicle access roads to and from the north and south of the LNG pump and vaporizer area. *EIS Section 4.12.3*

65. The **final design** of the vapor return system shall include provisions for the addition of LNG transfer pumps to the Jetty Drum D-103. The vapor inlet piping to the drum shall be

designed to ensure that all LNG, from the desuperheater and LNG piping discharging to the drum, cannot back flow to the vapor return piping. *EIS Section 4.12.3*

66. The **final design** shall include provisions for the future installation of LNG pumps for the boil-off gas (BOG) drum. *EIS Section 4.12.3*
67. The **final design** shall specify that the vapor inlet piping to the BOG drum shall be designed to ensure that all LNG, from the desuperheater and LNG piping discharging to the drum, cannot back flow to the vapor return piping. *EIS Section 4.12.3*
68. The **final design** shall specify that the Low Point Drain Drum is to be equipped to remove residual liquids without personnel accessing the spill containment sump. *EIS Section 4.12.3*
69. The **final design** of the Low Point Drain Drum shall include a pressure relief system, to protect the vessel in the event of isolation. *EIS Section 4.12.3*
70. The **final design** of the boil-off condenser system shall include a relief valve between the vapor inlet check valve and the fail-closed LNG outlet control valve. *EIS Section 4.12.3*
71. The **final design** shall include provisions to recycle the boil-off compressor discharge to upstream of the BOG drum desuperheater. *EIS Section 4.12.3*
72. The **final design** shall include car-seal or locked closed bypass valves around the intank pump ESD2 discharge valves as opposed to minimum stop set points for ESD2 valves, for cooldown of the 20-inch diameter header and piping. *EIS Section 4.12.3*
73. The **final design** shall include a shutoff valve at the suction and discharge of each high pressure pump. *EIS Section 4.12.3*
74. The **final design** shall specify that the minimum flow recycle line from the high pressure LNG pumps to downstream of the isolation valve to the LNG storage tanks shall be the same pressure and temperature rating as the piping at the discharge of the high pressure LNG pumps. *EIS Section 4.12.3*
75. The **final design** shall include a relief valve or operated vent valve sized for thermal relief at the discharge of each vaporizer, upstream of the isolation valves. This relief valve is in addition to the relief valve specified in NFPA 59A (2001 ed.) Section 5.4.1 and should be set at a lower pressure. *EIS Section 4.12.3*
76. The **final design** shall include LNG tank fill flow measurement with high flow alarm. *EIS Section 4.12.3*
77. The **final design** shall include a discretionary vent valve for each LNG tank, operable through the Distributed Control System (DCS). *EIS Section 4.12.3*
78. The **final design** shall include BOG flow and temperature measurement for each tank. *EIS Section 4.12.3*

79. The **final design** shall specify that all emergency shutdown (ESD) valves are to be equipped with open and closed position switches connected to the DCS/Safety Instrumented System (SIS). *EIS Section 4.12.3*

80. The **final design** shall include a clean agent system in the power distribution building. *EIS Section 4.12.3*

81. The **final design** shall include an analysis of the structural integrity of the outer containment of the full containment storage tanks when exposed to a roof tank top fire or adjacent tank top fire. *EIS Section 4.12.3*

82. The **final design** shall specify that all drains from high pressure LNG systems are to be equipped with double isolation and bleed valves. *EIS Section 4.12.3*

83. The **final design** shall specify that for hazardous fluids, branch piping, and piping nipples less than 2 inches are to be no less than Schedule 160. *EIS Section 4.12.3*

84. The **final design** shall specify that piping and equipment that may be cooled with liquid nitrogen is to be designed for liquid nitrogen temperatures, with regard to allowable movement and stresses. *EIS Section 4.12.3*

85. The **final design** shall include details of the shut-down logic, including cause and effect matrices for the process instrumentation, hazard detection system, and emergency shutdown system for alarms and shutdowns, including set points and voting logic. *EIS Section 4.12.3*

86. The **final design** shall include emergency shutdown of equipment and systems activated by hazard detection devices for flammable gas, fire, and cryogenic spills, when applicable. *EIS Section 4.12.3*

87. The **final design** shall include drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A. *EIS Section 4.12.3*

88. The **final design** shall provide an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap shall vent to a safe location and be equipped with a leak detection device that: shall continuously monitor for the presence of a flammable fluid; shall alarm the hazardous condition; and shall shut down the appropriate systems. *EIS Section 4.12.3*

89. The **final design** shall include a hazard and operability review of the completed design prior to issuing the P&IDs for construction. A copy of the review, a list of recommendations, and actions taken on the recommendations shall be filed. *EIS Section 4.12.3*

90. The **final design** shall include provisions to install high pressure boil-off compression or BOG liquefaction in the event that sendout operation is curtailed, or ceased for a period in excess of thirty days. Details shall include plans and drawings of the BOG recovery

system and specifications of the equipment and compressors to be installed. *EIS Section 4.12.3*

91. The **final design** shall include provisions to remove LNG from the inlet of the vaporizer due to shutdown sequence. *EIS Section 4.12.3*

92. The **final design** shall include a plan for clean-out, dry-out, purging, and tightness testing. This plan shall address the requirements of the American Gas Association's Purging Principles and Practice required by 49 CFR 193, and shall provide justification if not using an inert or non-flammable gas for cleanout, dry-out, purging, and tightness testing. *EIS Section 4.12.3*

93. The **final design** shall include a vent stack dispersion analysis to determine the proper placement of hazard detection devices that ensures venting is done in a safe manner. *EIS Section 4.12.3*

94. The **final design** shall specify that the vent stack be equipped with a discharge piece designed for ignited discharge conditions. *EIS Section 4.12.3*

95. The **final design**shall include certification that any modifications are consistent with the information provided to DOT as described in the design spill determination letter dated January 30, 2014 (Accession Number 20140203-4005). In the event that any modifications to the design alters the candidate design spills on which the Title 49 CFR Part 193 siting analysis was based, Downeast shall consult with DOT on any actions necessary to comply with Part 193. *EIS Section 4.12.5*

96. The **final design** shall include procedures to maintain and inspect the vapor barriers provided to meet the siting provisions of 49 CFR 193.2059. This information shall be filed a minimum of 30 days before approval to proceed is requested. *EIS Section 4.12.5*

97. The final design shall provide the following information:

    a. an evaluation that justifies the location of occupied buildings, including the main control building, administration building, and maintenance building, or a final design that relocates the occupied buildings or storage tank, so that the radiation from a storage tank roof top fire would be less than 10,000 Btu/ft$^2$-hr at occupied buildings.
    b. an evaluation that justifies the location of equipment that is critical to the safe shutdown and operation of emergency equipment, including the power distribution building transformers and emergency generator, or a final design that relocates the equipment or storage tank, so that the radiation from a storage tank roof top fire would be less than 10,000 Btu/ft$^2$-hr at the these locations.
    c. an evaluation that justifies the location of the vaporizers, high pressure pumps, and associated equipment, or a final design that relocates the equipment or impoundment, so that the radiation from a fire in the vaporizer spill impoundment would be less than 3,000 Btu/ft$^2$-hr at the vaporizer and high pressure pump equipment. *EIS Section 4.12.5*

98. **Prior to commissioning**, Downeast shall file plans and detailed procedures for: testing the integrity of onsite mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service. *EIS Section 4.12.3*

99. **Prior to commissioning**, Downeast shall provide a detailed schedule for commissioning through equipment startup. The schedule shall include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids, and during commissioning and startup. Downeast shall file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup will be issued. *EIS Section 4.12.3*

100. **Prior to commissioning**, Downeast shall file results of the LNG storage tank hydrostatic test and foundation settlement results. *EIS Section 4.12.3*

101. **Prior to commissioning**, Downeast shall tag all instrumentation and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves. *EIS Section 4.12.3*

102. **Prior to commissioning**, Downeast shall label equipment with equipment tag number and piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A. *EIS Section 4.12.3*

103. **Prior to commissioning**, Downeast shall file the design details and procedures to record and to prevent the tank fill rate from exceeding the maximum fill rate specified by the tank designer. *EIS Section 4.12.3*

104. **Prior to commissioning**, Downeast shall file operation and maintenance procedures and manuals, as well as safety procedures. *EIS Section 4.12.3*

105. **Prior to commissioning**, Downeast shall maintain a detailed training log to demonstrate that operating staff has completed required training. *EIS Section 4.12.3*

106. **Prior to introduction of hazardous fluids**, Downeast shall file a cooldown plan. During cooldown, Downeast shall report progress on the development of cooldown in daily reports. *EIS Section 4.12.3*

107. **Prior to introduction of hazardous fluids**, Downeast shall complete all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the Distributed Control System (DCS) and Safety Instrumented System (SIS) that demonstrates full functionality and operability of the system. *EIS Section 4.12.3*

108. **Prior to introduction of hazardous fluids**, Downeast shall complete a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s). *EIS Section 4.12.3*

109. **Prior to commencement of service**, Downeast shall develop procedures for offsite contractors' responsibilities, restrictions, and limitations and for supervision of these contractors by Downeast staff. *EIS Section 4.12.3*

110. **Prior to commencement of service**, Downeast shall notify FERC staff of any proposed revisions to the security plan and physical security of the facility. *EIS Section 4.12.3*

111. **Prior to commencement of service**, Downeast shall file progress on construction of the LNG terminal in **monthly** reports. Details shall include a summary of activities, problems encountered, contractor non-conformance/deficiency logs, remedial actions taken, and current project schedule. Problems of significant magnitude shall be reported to the FERC **within 24 hours**. *EIS Section 4.12.3*

112. Downeast shall receive written authorization from the Director of OEP **prior to commencement of service** at the LNG terminal. Such authorization will only be granted following a determination by the Coast Guard, under its authorities under the Ports and Waterways Safety Act, the Magnuson Act, the Maritime Transportation Security Act of 2002, and the Safety and Accountability For Every Port Act, that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by Downeast or other appropriate parties. *EIS Section 4.12.7.6*

**Recommendations 113 through 116 shall apply throughout the life of the facility:**

113. The facility shall be subject to regular FERC staff technical reviews and site inspections on at least an **annual basis** or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, Downeast shall respond to a specific data request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed piping and instrumentation diagrams reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted annual report, shall be submitted. *EIS Section 4.12.3*

114. **Semi-annual** operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions, abnormal operating experiences, activities (including ship arrivals/departures, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil-off/flash gas, etc.), and plant modifications including future plans and progress thereof. Abnormalities shall include, but not be limited to: unloading/loading shipping problems, potential hazardous conditions caused by off-site transportation, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, nonscheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, vapor or liquid releases, fires involving natural gas and/or from other sources, negative pressure (vacuum) within a storage tank and higher than predicted boil-off rates. Adverse weather conditions and the effect on the facility shall also be reported. Reports shall be submitted **within 45 days after each period ending June 30 and December 31**. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" shall also be included in the semiannual operational reports. Such information would provide the FERC staff with

early notice of anticipated future construction/maintenance projects at the LNG facility. *EIS Section 4.12.3*

115. In the event the temperature of any region of any secondary containment, including imbedded pipe supports, becomes less than the minimum specified operating temperature for the material, the Commission shall be notified **within 24 hours** and procedures for corrective action shall be specified. *EIS Section 4.12.3*

116. Significant non-scheduled events, including safety-related incidents (e.g., LNG, refrigerant or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security related incidents (i.e., attempts to enter site, suspicious activities) shall be reported to FERC staff. In the event an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification shall be made **immediately**, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification shall be made to FERC staff **within 24 hours.** This notification practice shall be incorporated into the LNG facility's emergency plan. Examples of reportable LNG or refrigerant related incidents include:

    a. fire;
    b. explosion;
    c. estimated property damage of $50,000 or more;
    d. death or personal injury necessitating in-patient hospitalization;
    e. release of hazardous fluids for five minutes or more;
    f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes gas, refrigerants, or LNG;
    g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas, refrigerants, or LNG;
    h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas, refrigerants, or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices;
    i. a leak in an LNG facility that contains or processes gas, refrigerants, or LNG that constitutes an emergency;
    j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;
    k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operation of a pipeline or an LNG facility that contains or processes gas, refrigerants, or LNG;
    l. safety-related incidents to LNG or refrigerant transportation occurring at or en route to and from the LNG facility; or

*m.* an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, FERC staff will determine the need for a separate follow-up report or follow-up in the upcoming semi-annual operational report. All company follow-up reports shall include investigations results and recommendations to minimize a reoccurrence of the incident. *EIS Section 4.12.3*

FEDERAL ENERGY REGULATORY COMMISSION
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